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Exploring the potential of carbon capture and storage-enhanced oil recovery as a mitigation strategy in the Colombian oil industry

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ABSTRACT

The use of CO_2 for enhanced oil recovery (CO_2-EOR) is a promising alternative for reducing the cost of carbon capture and storage (CCS). In this study the techno-economic potential of integrated CCS-EOR projects for reducing greenhouse gas (GHG) emissions in the Colombian oil industry is estimated. For this purpose, a source-sink matching process is carried out, including CO_2 capture potentials in sources from the petroleum, cement, power generation, and bioethanol industries, as well as from the CO_2 storage in suitable oil fields for EOR. The results indicate that a total of 142 million tons of carbon dioxide ($MtCO_2$) could be stored, while delivering 465 MMbbl through five CCS-EOR projects in four clusters identified around the country. The levelised cost for capture ranged between 12–209 €/tCO_2, followed by the cost of CO_2 during EOR operations with a variation of 24–59 €/tCO_2, and finally the CO_2 transport, from 1 €/tCO_2 to 23 €/tCO_2. The CO_2 mitigation potential of CCS-EOR represents 25 % of the forecasted oil industry emissions in Colombia for the period of 2025–2040. As compared to the intended nationally determined contribution (INDC) target set by the Colombian government, CCS-EOR projects could contribute 7 % of the total accumulated emissions reductions by 2040.

1. Introduction

Colombia is committed to reducing its greenhouse gas (GHG) emissions by 20 % with respect to its business-as-usual (BAU) scenario in 2010 by 2030, and could increase this target up to 30 % with the provision of international support (United Nations Framework Convention on Climate Change (UNFCC), 2015). The country accounts for approximately 0.4 % of the global emissions (Institute of Hydrology, Meteorology and Environmental Studies (IDEAM) et al., 2016); however, regarding its risk (vulnerability) from climate change, it ranked 19th in 2017, and 49th for the period from 1998 to 2017 (Eckstein et al., 2019). Colombia is a net exporter of fossil fuels. According to the International Energy Agency (IEA, 2017) in 2015, Colombia's energy production accounted for 5.3 EJ, with a final consumption of just 1.1 EJ as a result of a net export of 1.6 EJ of oil and 2.1 EJ of coal.

Colombia increased its GHG emissions by 15 % from 1990 until 2010, reaching a total of 281 million tons of carbon dioxide equivalent ($MtCO_{2\text{-eq}}$), i.e. the amount of CO_2 equivalent to a GHG in terms of global warming impact. The most updated GHG inventory for Colombia was issued in 2012, with 258 $MtCO_{2\text{-eq}}$. This inventory was dominated by the forestry (36 %) and agricultural sectors (26 %), followed by transportation (11 %), manufacturing industries (11 %), and mining and energy (10 %). The industrial, mining and energy, and transportation sectors account for 39 % of the total GHG emissions (Fig. 1), and have shown increases of 94 %, 85 %, and 53 %, respectively, for the period from 1990–2012. The total CO_2 emissions breakdown in Colombia by sector is shown in Appendix 7.1.

Besides the transport sector, the power generation, oil, and cement industries emit the most CO_2, and can be considered as potential sources of CO_2 for EOR projects in Colombia.

Globally, 4 % of total anthropogenic CO_2 emissions are released by the oil refining sector. CO_2 capture and storage (CCS) is a technology option with a recognised potential for mitigating CO_2 emissions (IEAGHG, 2017). The deployment of CCS on industries of high-value chemical products (e.g. oil refining, iron/steel production, ethylene manufacture, and ethanol production, among others) rather than power plants, might provide an ease absorption of the additional CO_2 capture cost into their production cost (Middleton et al., 2015). For the refining sector, CO_2 enhanced oil recovery (CO_2-EOR) is currently another potential option, as it allows for the use and storage of captured CO_2 to

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Nomenclature

MMscfd	Million standard cubic feet per day
bbl	Barrels of crude oil
MMbbl	Million barrels of crude oil
bpd	Barrels of crude oil per day
kbpd	Thousand barrels of crude oil per day
$CO_{2\text{-eq}}$	Amount of CO_2 equivalent to a greenhouse gas in terms of global warming impact.
EOR	Enhanced oil recovery
ICE	Internal combustion engine
MMP	Minimum miscibility pressure
OOIP	Original oil in place
FERC	Federal Energy Regulatory Commission
BAU	Business-as-usual
GHG	Greenhouse gas
HDT	Hydro-treatment process
FCC	Fluid catalytic cracking process
HCK	Hydro-cracking process
SMR	Steam methane reformer
ROW	Right-of-way
Mt	Million tons

reduce the emissions in the industry while maintaining oil production. CO_2 injection for incremental oil recovery has been performed commercially for decades, worldwide.

A recent update by the (IEA, 2019) estimates that 166 projects were injecting CO_2 out of the 375 EOR projects operating globally in 2017. The crude oil production of CO_2-EOR projects is approximately 0.5 million bpd. This volume accounts for approximately 20 % of the production of EOR operations, which in turn represents 2 % of the world oil production. Forecasts by the (IEA, 2019) predict that 1.64 million bpd will be produced with CO_2-EOR out of 4.5 million bpd from EOR in 2040 (which would represent 4 % of global production). Regarding the CO_2 storage potential, (IEA, 2015a) estimate a cumulative storage of 360 $GtCO_2$, through maximum-storage EOR + processes on a global scale.

The role and potential of the CCS-EOR industry as a mitigation strategy for the Colombian oil industry have not yet been fully explored. In a previous work (Yáñez et al., 2019), we found that there is significant potential, from a geological point of view, in CO_2-EOR systems. In this work, we take this step further by matching CO_2 sources and sinks, and exploring the techno-economical performance of the identified options. The aim of this study is to estimate the techno-economic potential of CCS-EOR for reducing GHG emissions in the Colombian oil value chain. For this purpose, the supply and demand of CO_2 are studied by including the CO_2 capture potential of the oil industry value chain and other relevant sectors, as well as the storage potential of CO_2-EOR. The state-owned oil company Ecopetrol S.A. was taken as a case study as it represents the complete chain of the oil industry in Colombia, with approximately 70 % of the crude oil produced, and 100 % of the oil transported and refined in the country.

The present paper is structured as follows. Section 2 describes the case study and the current situation of CO_2 emissions in Colombia. Section 3 describes the methodology and data used in this study. Section 4 presents the techno-economic performances of the potential CO_2-EOR configurations. Finally, Section 5 provides main conclusions and discussion regarding the results and uncertainties.

2. Methodology

This study was performed with the following steps. First, an inventory was made of the CO_2 emissions of the industrial sectors, and the capture potential in the selected industrial sources was quantified. Second, a matching of CO_2 sources and sinks was carried out at the cluster level, using the identified industrial emission points and suitable oil fields selected in (Yáñez et al., 2019). Third, potential routes for CO_2 transport were identified, by using dedicated gas pipelines between the sources and sinks identified by the matching. Finally, the economic feasibility was evaluated for each selected CCS-EOR project, using the estimated CO_2 costs for the capture, transport, and oil recovery stages.

2.1. CO_2 supply

2.1.1. CO_2 emissions inventory

This inventory focused on the industrial sectors with the highest

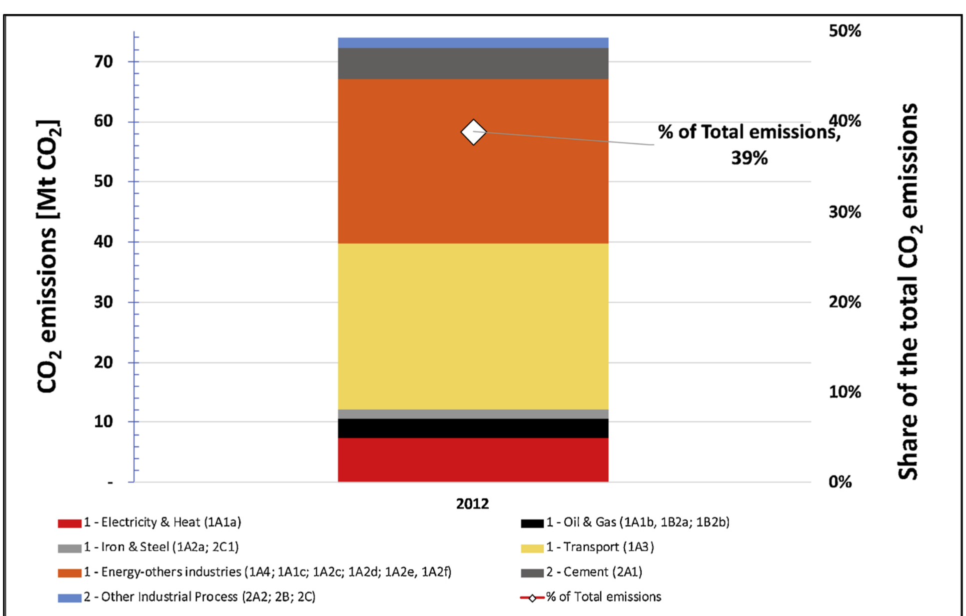


Fig. 1. CO_2 emissions in Colombia from the industrial, energy, and transport sectors (IDEAM et al., 2016). Categories in the legend follow the CO_2 emissions inventory guidelines from (IPCC, 2006). See more data in Appendix 7.1.

CO_2 emissions in Colombia, such as the oil, cement, and power generation industries. Although it has significantly lower emissions, bioethanol production was also included, owing to its highly-concentrated CO_2 emissions. These emissions are of great interest for EOR operations, and would only require compression and transport. CO_2 emissions are reported on an annual basis at a plant level for every sector. For inventory purposes, the identified sources were located within a range of 400 km of the leading oil basins.

2.1.1.1. Oil industry. The Colombian national oil company, Ecopetrol S.A., is responsible for the total production of crude oil and gas in Colombia, through direct and associated operations. Ecopetrol accounts for approximately 70 % of Colombian oil production, which reached 854 kbpd in 2017 (Agencia Nacional de Hidrocarburos (ANH), 2018). It also manages total oil transport through seven major pipelines, and has a crude oil refining capacity of 415 kbpd at two refineries as a result of its vertical integration (Ecopetrol S.A., 2015) (UPME, 2018).

In terms of quality, Colombian oil can be defined in the international market as heavy crude. This heavy oil represents approximately 60 % of the total crude oil produced in the country; medium oil accounts for 30 %, and light oil makes up just 10 %.

CO_2 emissions from the oil industry vary in volumes, ranging from sporadic leaks to hundreds of thousands of tonnes of CO_2 per year in a single process, and concentration levels of 10 %/v up to 95 %/v. CO_2 emissions are mainly associated with electricity and heat requirements, representing 60 % of the total emissions in the value chain (Yáñez et al., 2018). Other relevant sources are hydrogen production and catalytic cracking units during refining, and flaring in the extraction stage.

In this study, two refineries were considered: the Cartagena and Barrancabermeja refineries, each including hydrogen production, catalytic cracking, electricity, and steam production units. For the extraction stage, large facilities were considered as potential sources, including each of the gas-based turbine electricity generation units, gas treatment plants, gas-based furnaces, and internal combustion engines (ICEs). The transport stage does not represent significant CO_2 emissions in comparison with other stages of the oil value chain, and therefore, it was not considered as a potential source. In total, 31 points of sources with emissions higher than 30 ktCO_2/year were included in the inventory. On a yearly basis, CO_2 emissions by processing facility were collected from the 'Atmospheric Emission Management System' (SIGEA in Spanish) from Ecopetrol (Ecopetrol S.A., 2012a).

2.1.1.2. Cement industry. In 2016, the cement and clinker productions in Colombia reached 12.5 Mt and 9.9 Mt, respectively (El Ministerio de Minas y Energía (MINMINAS) and Departamento Administrativo Nacional de Estadística (DANE), 2017). As shown in Appendix 7.3, eight cement factories are responsible for more than 95 % of the national cement production, and emit approximately 4.7 MtCO_2/year.

CO_2 emissions in this industry are mainly produced during the calcination of limestone in cement kilns. From the cement sector, eight clinker production plants with a capacity of > 0.3 Mtcement/year were included in the inventory. The Colombian national emissions report (IDEAM et al., 2016) provides emission data by sector. However, no data was available at the plant or company level. Therefore, the CO_2 emissions per plant were calculated based on the Intergovernmental Panel on Climate Change (IPCC) emission factors, the cement production capacity, and the clinker-to-cement ratio for Colombia, as described in Appendix 7.2.

2.1.1.3. Power generation. Thermoelectric generation in Colombia comprises 17 plants that are responsible for 28 % of the 16.4 GW total net effective generation capacity in the country (XM, 2017). Gas-fired thermoelectric plants represent approximately 60 % of the national thermal generation, followed by coal-fired plants with 30 %. The generation capacities of the thermoelectric plants in Colombia range between 50 MW and 900 MW. For this study, thermoelectric plants with a capacity higher than 120 MW that were closely located to oil field regions were identified as potential sources. The CO_2 emissions inventory included 28 power generation units > 100 MW. In total, 28 coal, gas, and diesel fired-power plants were included in this inventory. The emission factors are described in Appendix 7.2.

2.1.1.4. Bioethanol. In Colombia, bioethanol is produced from sugarcane, mainly cultivated in the Cauca valley region in the southwestern part of the country. In total, there are seven ethanol production plants in Colombia with a total effective capacity of 2.1 ML of ethanol per day, and all were included in the inventory. The sugar fermentation process during the production of bioethanol generates an emission with a high CO_2 content that can exceed 95 % (see Appendix 7.3).

2.1.2. CO_2 capture

The capture of CO_2 can be carried out by three main competing routes:

- Post-combustion separates CO_2 from the flue gas of combustion-based process;
- Pre-combustion captures CO_2 from the syngas in gasification-based plants; and
- Oxy-combustion uses direct combustion of fuels with oxygen to produce a CO_2-rich flue gas ready for sequestration.

According to the literature, post-combustion technology seems to be the most suitable capture technology to be considered in the short term for the industries selected in this study. The technical performance data, energy consumption, investment, and operational costs were taken from literature scaled to the sizes of the industrial sources selected, and were used to calculate the CO_2 capture potential. The data used for the refinery, cement, power generation, and ethanol industries were taken from (IEAGHG, 2017), (Kuramochi et al., 2012), (IEAGHG, 2018a), and (Knoope et al., 2014), respectively.

There is a particular case in the CO_2 capture of gas associated with oil production. The CO_2 is at a concentration of approximately 75 %, whereas other light hydrocarbons (C1–C5) represent 20 %. Using a post-combustion process to capture this CO_2 would not be attractive given the low volume available, which would increase costs significantly. Besides, there is interest in recovering the light hydrocarbons. Thus, as an alternative, the Joule-Thomson[1] process could be used for the separation of the light hydrocarbons, and thus increase the concentration of CO_2 up to 90–95 %. This would make it viable for use in the recovery processes. Internal estimates calculate a capital expenditure (Capex) for the capture process of approximately 0.4 M$ (Ecopetrol S.A., 2014). However, the CO_2 compression cost described by (Knoope et al., 2014) was assumed, owing to the lack of information on the emitter point and the probable low cost of these systems.

A description of CO_2 capture technologies by sector is provided in Appendix 7.5. The rest of this section describes key performance indicators (KPI) used to evaluate the CO_2 capture technologies.

2.1.2.1. Key performance indicators

2.1.2.1.1. Technical. This study used the CO_2 emissions captured per year as the main technical indicator. The volume of CO_2 captured per year was calculated using the average capture efficiency of the post-combustion technology per each industrial process (based on the literature) and the CO_2 emission rate, which in turn was based on the processing capacity, operating time, net utilisation factor, and CO_2

[1] The Joule-Thomson effect describes the change in temperature of a fluid under a pressure decrease in an adiabatic process, and can be used for condensable hydrocarbon recovery. The significance of this effect in the downstream and upstream of the oil industry is described by (Yadali Jamaloei and Asghari, 2015).

Table 1
Parameters for technical and economic performance calculations in the CO_2 capture analysis.

Parameter	Unit	Value	Reference
Discount rate [1,2]	%	12	(Yáñez et al., 2018)
Economic lifetime [2]	Years	25	
Total Plant Cost (TPC)	%-PPC	130	(Berghout et al., 2013)
Total Capital Requirement (TCR)	%-TPC	110	(Berghout et al., 2013)
Energy prices [3]			
Natural gas price	€/GJ	4.1	(Bolsa Mercantil de Colombia, 2019)
Coal price	€/GJ	1.1	(UPME, 2016)
Electricity price	€/MWh	81	(Ecopetrol S.A., 2017)
Utilisation factor			
Cement [4]	[%]	75	(Ministerio de Minas y Energía, 2017) (Miguel Ángel Hernández Calderón Celia Elena Nieves de la Hoz, 2015)
Oil industry	[%]	95	(Ecopetrol S.A., 2012a)
Power Generation	[%]	75	(XM, 2017)
Ethanol	[%]	56	(Fedebiocombustibles, 2018)

[1] The interest rate has a significant influence on the CO_2 capture cost. This parameter is highly influenced by the specific industry sector and the economic region worldwide. This study uses 12 % as suggested by the state-own company in Colombia, which also reflect economic conditions for Latin America. A recent study by (IEAGHG, 2017) uses 8 % for the European oil refining industry. A discount rate of 10 % is usually adopted for the cement industry as shown by (Kuramochi et al., 2012); meanwhile 8 % is recommended for the power generation sector by the (IEAGHG, 2018a).
[2] Except for the cement plants which use 20 years according to (Kuramochi et al., 2012).
[3] Prices used are specific to Colombia.
[4] Calculated for total cement production in 2016 referred to the nominal capacity described in (Miguel Ángel Hernández Calderón Celia Elena Nieves de la Hoz, 2015).

emission factor. (Eq. (1))

$$m_{CO_{2_i}} = \eta_j \times (C_i \times U_{f_j} \times EF_{CO_{2_j}}) \tag{1}$$

here:

$m_{CO_{2_i}}$: *CO_2 emissions captured per year from the industrial source i,* $[tCO_2/year]$;

η_j: *CO_2 capture efficiency for industrial sector j,* $[\%]$;

C_i: *Processing capacity of industrial source i,* $[t\ of\ product/hour]$;

U_{f_j}: *Utilisation factor for industrial sector j* $[\%]$*; total or real output/nominal or maximal output; and*

$EF_{CO_{2_j}}$: *CO_2 emission factor for industrial sector j,* $[t\ CO_2/t\ of\ product]$.

2.1.2.1.2. Economic. The economic indicator used in this study is the CO_2 capture cost (C_{CO_2}: €/tCO_2 *captured*) for the CO_2 capture performance. In the power generation industry, the CO_2 capture cost is based on the difference between the levelised cost of electricity (LCOE) calculated with and without the capture process (IEAGHG, 2017). In the power sector, the CO_2 capture cost calculation is different, because the net power output and/or specific fuel consumption is affected by the capture process. (Eq. (2))

$$C_{CO_2(power)} = \frac{(LCOE)_{CC} - (LCOE)_{ref}}{\left({}^{tCO_2}/_{MWh}\right)_{CC}} \tag{2}$$

here:

$(LCOE)_{CC}$: *LCOE produced by the plant with carbon capture, [€/MWh];*

$(LCOE)_{ref}$: *LCOE produced by the plant without carbon capture, [€/MWh]; and*

$(tCO_2/MWh)_{CC}$: *CO_2 emission rate to the atmosphere of the plant with carbon capture [tCO_2/MWh].*

However, in other industries where the carbon capture process usually does not affect the product outputs of the plant, the CO_2 capture cost calculation can be simplified, as shown in Eq. (3).

$$C_{CO_2(other\ industries)} = \frac{(Annualized\ Capex\ +\ Annualized\ Opex)}{Annual\ amount\ of\ CO_2 captured} \tag{3}$$

The investment for the CO_2 capture (i.e. the Capex) is based on the additional costs for the capture, conditioning, compression, and additional combined heat and power (CHP) for a plant with unchanged production (except for the power generation). The Capex is expressed as a total capital requirement (TCR), with standard percentages used to account for indirect costs as follows: TCR = 110 % of total plant cost (TPC) and TPC = 130 % of process plant cost (PPC). The PPC comprises equipment and installation costs. The TPC comprises the PPC and engineering fees and contingencies, and in turn, the TCR comprises the TPC, owner costs, and interest during construction (Berghout et al., 2013). The annualised Capex is calculated by multiplying the investment cost (I) with an annuity factor (α) (see Eq. (4)). The annuity factor is obtained from the discount rate (r) and lifetime (LT) of the project, as shown by Eq. (5).

$$Capex = \alpha \times I \tag{4}$$

$$\alpha = \frac{r}{1-(1+r)^{-LT}} \tag{5}$$

2.1.2.2. Standardisation of key parameters for CO_2 capture

2.1.2.2.1. Indexation. All cost figures were converted to €,$_{2017}$. Inflation was accounted for by applying the 'Upstream Capital Cost Index' (UCCI) and the 'Harmonised Indices of Consumer Prices' (HICP). Costs reported in U.S. dollars were first converted to US$,$_{2017}$ using the UCCI, then a year-averaged €/$ currency conversion rate was applied.

2.1.2.2.2. Normalisation of plant scales. The capital cost is highly dependent on the size (capacity) of the plant. Capital costs were calculated by applying a generic scaling relation to figures from literature to consider the plant capacity of a CO_2 emission source (Eq. (6)).

$$\frac{Cost_A}{Cost_B} = \left(\frac{Scale_A}{scale_B}\right)^{SF} \tag{6}$$

In the above, SF is defined as the scaling factor. A scaling factor of 0.67 was assumed, according to (Berghout et al., 2017). The techno-economic parameters for the industrial CO_2 sources investigated in this study are provided in Table 1.

2.2. CO_2-enhanced oil recovery (EOR) potential

2.2.1. Screening

The screening of suitable oil fields for CO_2-EOR processes is based on the use of technical criteria that discretely include or exclude fields from a list of potential candidates. This methodology varies from detailed numerical analysis to a more crude and broad level, depending on the scope of the study. Recently, (Bachu, 2016) summarised the ranges accepted for the most relevant screening criteria, from which oil gravity, minimum miscibility pressure (MMP), and reservoir size were identified as the factors with the most significant impacts. (Núñez-López et al., 2008) defined the MMP as the most critical constraint for a CO_2-EOR application, which in turn is a function of the oil properties, the pressure and temperature of the reservoir, and the CO_2 purity.

In a high-level analysis (as proposed for this study), the screening process can be challenging, as a comprehensive database and resource-intensive process is required. Yáñez et al. (2019) reviewed different screening approaches, and proposed a rapid method for a high-level assessment using criteria as follows: a) original oil in place (OOIP) with a minimum volume of 50 MMbbl, b) the oil fields must be undergoing or have an existing water flooding process, and c) an original pressure higher than the MMP.

Their study initially identified 13 oil fields suitable for EOR using Criteria 1 and 2. Six meet all three criteria, and are therefore optimal candidates. As the first two criteria primarily evaluate economic and technical performances, this study used the list of 13 oil fields, as presented in Table 2. Yáñez et al. (2019) also calculated the CO_2 storage and oil recovery potentials, assuming unlimited CO_2 supply and based on the geological properties of the reservoir and an expected oil recovery factor. A summary of the followed steps for the calculation is presented in appendix 7.4.

2.2.2. CO_2-EOR

The economic model for the CO_2-EOR process involves three main modules: injection, production, and recycling. The CO_2 injection cost includes new drilling, or reworking wells to be used as injectors and producers. The production stage requires new corrosion-resistant infrastructure to manage oil, water, and gas. The recycling process includes the CO_2 separation, and its compression for injection into the well (NETL, 2012). This technique is a capital-intensive process, although the cost is comparable to secondary oil recovery operations with a site and a situation-specific associated cost (Advanced Resources International, 2011).

An integrated CCS-EOR project considers the CO_2 capture at the emitter points, and then its transport through dedicated pipelines to the oil fields for the EOR. In this study, it was assumed that a constant CO_2 flow was delivered to the oil fields during the lifetime of the CCS-EOR project. In commercial CO_2-EOR operations, the flow of injected CO_2 may change throughout the life of the project. For example, the CO_2 flow increases in the early phase, and then decreases as the oil is produced along with CO_2 to be recycled. In CCS-EOR projects, however, there is a need to receive and inject a constant CO_2 flow as captured at the emitter points. A constant CO_2 flow can be managed by staggering the drilling and injecting operations in phases, as necessary to approximate continuous CO_2 delivery (King et al., 2013). This approach is also assumed for commercial operations that involve CO_2 captured from industrial sources.

This study follows the cost model structure for a CO_2-EOR project described by (Tayari et al., 2018) which combined different approaches from the literature. The model includes the main cost modules suggested by (Advanced Resources International (ARI), 2014) and also uses operational costs from the West Texas EOR operations from the Energy Information Administration (EIA, 2010). A methodology proposed by (Fukai et al., 2016) can also be advantageous on top-level estimates for economic feasibility studies of CO2-EOR projects, which rely on the CO2 break-even price calculated for a range of oil prices. The cost model for a CO_2-EOR project in this study follows the structure proposed by (Tayari et al., 2018), and is shown in Table 3.

Every stage in the cost model is compounded with a sub-module for specific cost objects. Although this is a general cost model, country-specific assumptions were applied to Colombia[2]. The oil recovery from the selected reservoirs was analysed within a 20–25 y time frame, as in a typical CO_2-EOR project (Lorsong, 2013).

A detailed description of the CO_2-EOR cost calculation is provided in Appendix 7.6. The key technical and economic indicators used in the cost model for CO_2-EOR operations are presented in Table 4.

[2] Oil production costs are highly dependent on the costs of drilling and development of wells. These, in turn, are sensitive to efficiency in drilling and completion that relate to the depth of the well, type of drilling and completion. The key elements in the cost for onshore well are land acquisition; capitalised drilling, completion, and facilities costs lease operating expenses and gathering processing and transport costs. The average cost range from 4.9 to 8.3 million, with completion cost, assumes around 60-70% of this cost (EIA, 2016). In Colombia, Ecopetrol has reduced the cost of drilling from $ 7.4 in 2014 to $ 3.8 million in 2016 through the use of more efficient drills that reduce drilling time and cost. However, these production costs can be profoundly affected by external factors related to the acquisition and access to the land of the drilling area such as environmental, social, tax and security.

Table 2
Candidate oil fields for CO_2-enhanced oil recovery (EOR) process in Colombia (Yáñez et al., 2019).

Oil Field [Code name][1]	Depth [m]	Oil gravity [API]	Pressure [MPa]	CO_2 Storage Potential [2] [Mt]	Oil recovery potential [2] [MMbbl]
A	1524	20.5	19	42.7	145.2
B	2362	43.8	23	12.1	41.3
E	2134	28.2	18	8.8	18.5
G	2134	26	28	41	139.6
H	1518	23.9	16	64.3	218.9
I	1812	34	18	3.2	6.8
J	2225	21	22	40.9	139.2
K	975	19	48	13.8	47.1
M	3196	30.5	30	5.3	11
N	762	26	13	4.4	9.3
O	3188	30.5	30	4.1	8.5
P	1935	33.8	18	2.5	5.2
Q	2603	30.1	26	4.7	16

[1] The oil fields names have been coded as they must be kept confidential.
[2] a more detailed explanation of the calculation steps for the CO2-EOr potential is presented in appendix 7.4.

2.3. Source-sink matching

The matching methodology used in this study involves three main steps: (i) identification of clusters to deploy CCS-EOR projects, (ii) ranking of CO_2 sources and preselected oil fields, and (iii) a matching process based following a merit order defined by the ranking. It should be noted that this study considers a relatively low number of sources and sinks for the matching process. This limitation is partly owing to the current characteristics of the industrial sectors in Colombia, and also because they have been pre-screened, as is the case for the candidate oil fields for EOR. For a more complex assessment that involves a large number of sources and sinks exist is optimisation models for integrated system design such as *SimCCS*, which specially design CCS infrastructure networks (Middleton et al., 2020). The matching process in this work proposes a simple logical criteria-based method for identifying possible business cases for CCS-EOR projects. Every match aims to deploy a CCS-EOR project for a 20–25-y lifetime. The specific CO_2 injection time was calculated using the potential storage capacity and the CO_2 flow available by the sink and source, respectively.

2.3.1. Identification of clusters

This step identified geographical regions (clusters), as defined by the presence of CO_2 sources and potential sinks. Potential matches should be at distances below 300 km, (Bachu, 2016) and at locations where infrastructure is available, such as transport roads and/or gas pipelines.

2.3.2. Ranking

Technical and logistical criteria were used to classify sources and sinks per cluster, to prioritise their feasibility for a CCS-EOR project. The ranking process was based on using weighting coefficients, and threshold values were assumed for every criterion, as proposed by (Bachu, 2016).

Table 3
Structure of the cost model for CO_2-EOR process.

Injection	Production	Recycling
Lease equipment cost	Producing equipment cost	Processing and compression
Annual O&M cost	Fluid lifting cost	Separating cost
Distribution cost	Water/oil separation cost	Compression cost
Surfactant cost	Revenue, tax, and royalties	Pumping cost
Water cost		

Table 4
Key indicators of the CO_2-EOR cost model.

Parameter	Unit	Value	Reference
Royalty [1]	%	8 to 25	(Congreso de la República de Colombia, 2002)
Volume of water injected (expressed as % oil production)	%	25	(Tayari et al., 2018)
Running time – injection pump	hours	8760	This study
Water supply cost	€/bbl	0.10	(Advanced Resources International and ARI, 2014)
Electricity cost	€/kWh	81.11	(Ecopetrol S.A., 2017)
Mechanical efficiency- injection pumps	%	70	(Tayari et al., 2018)

[1] This is a function of the oil production volume and applies both, to conventional and enhanced oil recovery process according to the law 756/2002 (Congreso de la República de Colombia, 2002002). See calculation criteria in appendix 7.12.

The CO_2 sources were ranked following the following criteria: a) industry sector (oil industry, others); b) operational status (running, on-project); c) CO_2 concentration (low: < 45 %, medium: < 45 %, high: > 75 %); and d) distance to the largest oil fields (low: < 15 km, medium: < 60 km, high: > 60 km). The oil fields (sinks) were ranked using the following criteria: a) distance to the largest CO_2 source; b) CO_2 storage capacity (Low: < 1 Mt, medium: < 10 Mt, high: > 10 Mt); and c) oil recovery potential (Low: < 10 MMbbl, medium: < 50 MMbbl, high: > 50 MMbbl). These parameters are proxies for the techno-economic criteria of the stages involved, in this case, for a CCS-EOR project, as discussed by (Bachu, 2016).

In the case of CO_2 sources, for instance, the feasibility of a CCS-EOR project improves if the plant is currently running, with a low CO_2 concentration and with short distances to the oil fields. For the oil fields, the feasibility improves with decreasing distance to the sources, and with increasing storage capacity and oil recovery potential. The weighting coefficients express the relative importance of each parameter in relation to a specific source or sink being analysed, and can be adjusted to reflect particular conditions. (See Eqs. (7) and (8)).

$$R_i = \sum_{x=1}^{3} \sum_{th=1}^{3} (C_{i,x} \times W_x \times Z_{th,x}) \tag{7}$$

here:

$$\sum_{1}^{x} W_x = 1$$

R_i:Ranking value for reservoir i;

C_{ix}:A Boolean value (1,0) that indicates whether the threshold range evaluated for each criterion applies to the reservoir i;

W_x:Weight factors defined for ranking reservoirs; and

$Z_{th,x}$:A value assigned for each threshold range (th) in every criterion x.

$$R_j = \sum_{y=1}^{3} \sum_{th=1}^{3} (C_{j,y} \times W_y \times Z_{th,y}) \tag{8}$$

here:

$$\sum_{1}^{y} W_y = 1$$

R_j:Ranking value for source j;

$C_{j,y}$:Boolean value (1,0) indicating whether the threshold range evaluated for each criterion applies to the source j;

W_y:Weight factors defined for ranking reservoirs; and

$Z_{th,y}$:A value assigned for each threshold range (th) in every criterion y.

2.3.3. Matching

The matching process was based on a merit order, starting with the sources and sinks that scored the highest during the classification carried out in the previous step. For the highest-scoring reservoir, an appropriate match was initially made with the first source in the ranking. A ratio (Y) was calculated, using the storage capacity of the reservoir and the size of the CO_2 emitter (Eq. (9)). This ratio indicated an estimated time of the CO_2-EOR project, which was assumed in this study as 20–25 y for the matching. When Y_{ij} was lower than expected, a new CO_2 source was added to the match, and the ratio was re-calculated.

$$Y_{ij} = \frac{S_i}{A_{CO2j}} \tag{9}$$

here:

Y_{ij}:Estimated time of storage capacity of reservoir i in relation to emissions from source j, [years];

S_i:Storage capacity of reservoir i, [$MtCO_2$]; and

A_{CO2j}:Amount of CO_2 emitted annually by the source j, [$MtCO_2$/year].

The matching process is described as follows. The match M_{ij} of a source j injecting CO_2 into a reservoir i was determined by the estimated time of the project, defined as $20 \le Y_{ij} \le 25$. If $Y_{ij} \le 20$, then a new source was added to the match as M_{i+1j}, but if $Y_{ij} \ge 25$, a new reservoir could be considered for the match (defined as M_{ij+1}). In a matching process with a significant number of sources and reservoirs and without a definition of clusters, a ranking of potential matches based on the normalisation of each criterion can be used, as described by (Bachu, 2016).

2.4. CO_2 transport

The transport of CO_2 refers to the second stage of an integrated CCS-EOR project, which is responsible for taking the gas through a dedicated pipeline from the emitter source to the wellhead at the oil field. CO_2 transport is often proposed for a dense phase above its critical point, i.e. a pressure (P) higher than 7.4 MPa and a temperatures (T) below 31.1 °C. The pressure can be defined by meeting a specific storage requirement. In regular operations using a liquid phase, the pressure is set as P > = 8 MPa, and for a gas phase, between 1.5–3 MPa (Knoope et al., 2014).

Detailed information on the costs of a CO_2 pipeline is mainly confidential, owing to commercial reasons. However, it is possible to estimate the capital cost of CO_2 pipeline projects by using reliable sources, such as the National Energy Technology Laboratory (NETL) guidelines (NETL, 2017). (IEAGHG, 2014) identifies terrain, length, and capacity as the key factors with the strongest influence on the cost of a CO_2 pipeline.

The CO_2 transport cost reported in the literature varies widely, primarily based on whether or not the compression cost is included. Moreover, the cost model approach is diameter or mass flow-based, and usually underestimates the capital cost of the CO_2 pipeline, as costs are directly based on US natural gas pipelines (Knoope et al., 2013).

This study follows the CO_2 transport model design approach described by (Knoope et al., 2014), which follows the cost model structure provided in Table 5. A detailed description of the CO_2 transport costs model is provided in Appendix 7.7. The model is based on the physical properties of the CO_2 transport and the materials for pipeline construction, unlike previous models based on natural gas transport and on a diameter or mass flow-specific cost.

Table 5
Structure of the cost model for CO_2 transport.

Pumping	Compression	Pipeline
Equipment cost Energy cost O&M	Equipment cost Energy cost O&M	Material cost Labour cost ROW cost O&M

The key economic indicator in the CO_2 transport cost model is the levelised cost, defined as presented in Eq. (10).

$$C_{T_{CO_2}} = \left(\frac{\alpha \times (I_{pump} + I_{comp}) + \alpha \times I_{pipe} + OM_{pump} + OM_{comp} + OM_{pipe} + EC_{pump} + EC_{comp}}{m \times H \times 3.6} \right) \tag{10}$$

here:

$C_{T_{CO_2}}$:Levelised CO_2 transport cost, [€/tCO_2];

α:Annuity factor, as described by Eq. (5);

I_{pump}, I_{comp}, I_{pipe}: Investment costs of pumps, compressors, and pipeline respectively [€];

OM_{pump}, OM_{comp}, OM_{pipe}: Operation and maintenance (O&M) costs of pumps, compressors, and pipeline, respectively [€];

EC_{pump}, EC_{comp}: Energy costs of pumps and compressors, respectively [€];

m: CO_2 mass flow, [kg/s]; and

H: number of operations hours per year.

The transport cost used the Euclidean distance between sources and sinks, as calculated from the CO_2 pipeline layout for every identified cluster. As the CO_2 pipeline connects several capture points, the volume of CO_2 per section can change significantly, and thus affect the Capex. The cost of transporting CO_2 was calculated for pipeline sections, which represent significant changes in the CO_2 volume. The costs per section were summed to estimate the total transportation cost for a specific project.

Following the cost minimisation results from (Knoope et al., 2014), the CO_2 inlet pressure was standardised at 13 MPa for the transport pipeline design. This optimised pressure (for a lower transportation cost) was obtained for CO_2 liquid transportation onshore, at short distances (50 and 100 km) and mass flows (50 and 100 kg/s).

Table 6
Key indicators of the CO_2 transport cost model.

Parameter	Unit	Value	Reference
Running time	hours	8760	This study
Design lifetime of the pipeline	years	50	(Knoope et al., 2014)
Design lifetime of compressors and pumps	years	25	(Knoope et al., 2014)
Interest rate	%	12	(Yáñez et al., 2018)
O&M costs compressor/pumps	%	4.0	(Knoope et al., 2014)
O&M costs pipeline	%	1.5	(Knoope et al., 2014)
Electricity cost	€/kWh	81.11	(Ecopetrol S.A., 2017)
Steel cost [1]	€/kg	1.41	This study
ROW cost	€/m	83	(Knoope et al., 2014)
Labour cost [2]	€/m^2	660	(Knoope et al., 2014)
Miscellaneous cost (Material + labour))	%	25	(Knoope et al., 2014)

[1] The steel costs reported by (Knoope et al., 2014) are based on the price of Heavy steel plate used in steel construction, which is similar to the cost of steel pipeline as summarised in their study. However, the price of steel showed a notable increase during the period 2010–2012 and recently, prices for the hot-rolled plate in steel report values between 0.6 and 0.7 €/kg according to worldsteelprices (https://worldsteelprices.com/) and Steelbenchmarket (http://www.steelbenchmarker.com/). Given the variation in prices and considering that (Knoope et al., 2014) established that by doubling steel prices the total cost of the pipeline is affected between 20 and 35 %, it was decided to assume the value reported by (Knoope et al., 2014)and updated to € 2017 with the UCCI.

[2] Using a location factor for south-America from (IEAGHG, 2002) as suggested by (Knoope et al., 2014).

A summary of the key techno-economic indicators is presented in Table 6.

2.5. Economic analysis

The net present value (NPV) was used to evaluate the profitability of selected CCS-EOR cases (see Eq. (11)). The Capex, operating expenditure (Opex), and levelised cost of CO_2 were estimated for every stage of the project, such as in the capture, transport, and EOR operations.

$$NPV = -(I_C + I_T + I_{EOR}) + \sum_{t=0}^{T} \left(\frac{(R_O - (C_C + C_T + C_{EOR} - C_{Cr}))}{(1 + r)^t} \right) \tag{11}$$

here:

I_C:Capex for capture, [M€];

I_T:Capex for transport, [M€];

I_{EOR}:Capex for CO_2-EOR, [M€];

R_O:Revenues from additional oil production, [M€/year];

C_C:O&M for CO_2 capture, [M€/year];

C_T:O&M for CO_2 transport, [M€/year];

C_{EOR}:O&M for CO_2-EOR, [M€/year]; abd

C_{Cr}:CO_2 credits[3], [M€/year]; assumed as 4.6 €/t CO_2 according to the Colombian government (Congreso de la República de Colombia, 2016), and updated for 2019 as defined by (DIAN, 2019)

Oil production revenues (R_O) were calculated using the model provided by (Van' T Veld et al., 2010), assuming constant production (see Eq. (12)).

$$Oil\ Revenue = \sum_{t=1}^{t=n} P^o \times Q^o \times (1 - \tau^R) \tag{12}$$

here:

P^o:Oil price, [€/bbl]; using an average Brent[4] oil price of 58 €/bbl in

[3] It should be considered that according to the 1819 law of 2016 of the Colombian government, the carbon tax is charged to the consumption of fossil fuels and not to CO_2 emissions, as in other international markets. In this sense, the CO_2 credit is taken as a reference for the potential benefit for the CCS-EOR project of selling the credits in the international carbon market.

[4] Brent (North Sea d North Atlantic crude traded at Sullom Voe terminal in Scotland) and West Texas Intermediate-WTI (U.S. mid-continent crude traded at Cushing Oklahoma) are two of the most important benchmarks of crude oils, and are used as references for pricing oils. (API, 2014)

Table 7
Sectoral breakdown of number of plants, CO_2 emissions, and concentration in the flue gas of the inventory used in this study.

Sector	Number of installations [a]	CO_2 emission [$MtCO_2$/yr]	Typical range for CO_2 concentration	References
Oil industry [b]	30	5.9	10 %-95 %	(Ecopetrol S.A., 2013)
Power generation	28	7.3	3%-4 %	(Berghout et al., 2015)
Cement [c]	8	4.7	15 %-30 %	(IEAGHG, 2018b)
Bio-Ethanol [d]	7	0.3	> 95 %	(Ecopetrol S.A., 2012b)
Total	73	18.1		

[a] It is identified as an emitter point (process unit).
[b] Data refers to combustions related CO_2 emissions, hydrogen production and natural CO_2 production in oil wells.
[c] Emissions by calcination of limestone.
[d] Emissions from fermentation process.
[e] For a Natural Gas-fired Combined Cycle (NGCC). In the case of a pulverised coal-fired power plant CO_2 concentration is higher.(12–14 %).

2017;

Q^o:Oil production rate, [bbl/day];

τ^R:Royalty, [%]; the Colombian government establishes an 8 % royalty for the EOR operations; and

n:Time period.

2.6. Mitigation potential

To assess the impact of CCS-EOR in national GHG emissions, the CO_2 storage potential was compared with emissions forecasting for the oil sector to 2040, as well as with the reduction target established by the Colombian government for 2030. For this comparison, the CO_2 capture and injection potential per year of the selected matches in each cluster is considered. It is assumed that projects have a preparation and development period of 5 y; thus, CO_2 would effectively be injected as of 2025.

2.7. Data sources

Sector	CO_2 Sources	Description	Base year	Reference
Oil [a]	Extraction: *CHP, TC, TG, FH, ICE NatCO$_2$*. Refinery: *FCC, H2, HDT, CHP, Bo, HCK, DCK.*	For each selected process unit, CO_2 emissions per year were collected from the Atmospheric Emission Management System (SIGEA[b] in Spanish) in Ecopetrol. Properties of CO_2 flows at the refinery such as %v, temperature and pressure. Project on development.	2016	(Ecopetrol S.A., 2012a) (Ecopetrol S.A., 2013)
Cement	Calcination process	a Location and process type. b Capacity c emission factor d utilization factor e Clinker to cement ratio	2018	a (Miguel Ángel Hernández Calderón Celia Elena Nieves de la Hoz, 2015) b (ARGOS, 2015)(ARGOS, 2018) (CEMEX, 2018a)(CEMEX, 2018b) c (IPCC, 2000) d (DANE, 2018) e (Ministerio de Minas y Energía, 2017)
Power generation	Flue gas	a Location and process type. b Capacity c emission factor d utilization factor	2018	a (CONCENTRA, 2018) b (XM, 2017). c (UPME et al., 2016) d (XM, 2017)
Bioethanol	Sugarcane fermentation process.	a Location. b Capacity c emission factor d utilization factor	2017	a (Fedebiocombustibles, 2017). b (Fedebiocombustibles, 2018) c (Ecopetrol S.A., 2012b) d (Fedebiocombustibles, 2018)
Colombia	By sector	National GHG inventory	2012	(IDEAM et al., 2016)

[a] Process unit code: R: Refinery; H2: Hydrogen production; HDT: Hydrotreatment plant; FCC: Fluid Catalytic Cracking; CHP: Cogeneration; HCK: Hydrocracking; DCK: Delayed coker; F: Upstream Facility; TC: Turbo-compressors; TG: Turbo-powers; FH: furnace/Heater; ICE: internal combustion engine; Bo: Boiler; NatCO$_2$: Natural CO_2 source.

[b] SIGEA is an audited information system in Ecopetrol to provide up to date information about calculation and emissions inventory at a process level. This system gathers data online from facilities about fuel, steam and electricity consumption, and also upload data from emissions measurements at the field to calculates CO_2 emissions by a processing unit.

3. Results

3.1. CO_2 industrial sources

In this study, 73 sources of industrial CO_2 emissions in Colombia were identified, accounting for 18 $MtCO_2$/year (977 million standard cubic feet per day (MMscfd)). A total of 30 CO_2 emissions sources were identified from the oil industry, accounting for 33 % of the CO_2 inventory, and refineries represent two-thirds of this share. Moreover, 28 emission sources were identified from power generation plants, 8 sources from the cement industry, and 7 sources from ethanol production plants, with 39 %, 26 %, and 2 % shares of the total inventory, respectively (Table 7). A detailed description of the CO_2 industrial sources included in this study is provided in Appendix 7.3.

Fig. 2 compares the CO_2 emissions by industrial sector as considered in this study with those reported in the national GHG inventory in Colombia. The CO_2 emissions inventory from this study accounts for 10 % of the total CO_2 emissions in Colombia. The cement and power

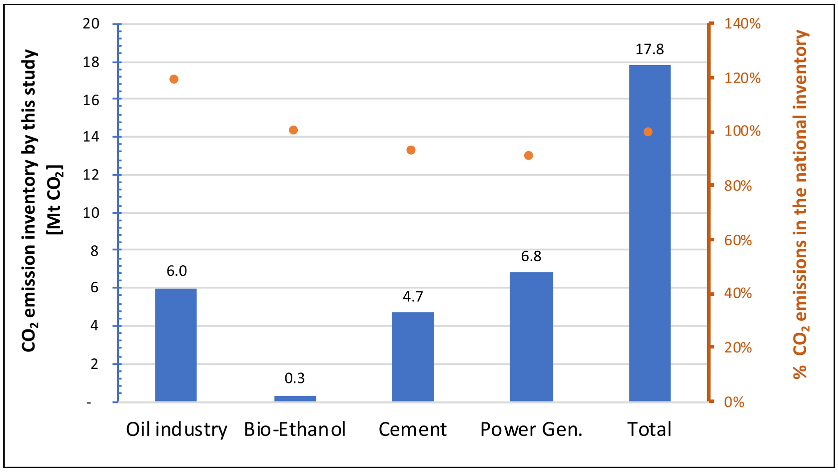


Fig. 2. CO_2 emission sources by sector included in this study[7] compared to the national CO_2 inventory (IDEAM et al., 2016).

generation emissions represent approximately 100 % of those reported by the national inventory. Nevertheless, our emissions inventory is higher for the oil and bioethanol industries. For the first case, the emissions from the extraction stage in 2017 are based on our own calculations and measurements, unlike the national inventory from 2012, which is based on emission factors. For bioethanol, the slight difference is owing to the use of a single utilisation factor for all the included factories.

The location of the CO_2 industrial sources from the oil, cement, power generation, and bioethanol industries in Colombia are shown in Fig. 3. Large CO_2 sources are mainly located in the central and the northern regions of the country along the Magdalena river valley, and between the central and east regions of the Andes mountain chain. The largest individual CO_2 sources are two refineries located in the central and northern region, respectively.

3.2. Oil fields for CO_2-EOR

Colombia has 23 sedimentary basins covering an area of 70,000 km^2 out of a 1.14 million km^2 total country area (ANH, 2007) (Ketner and David, 1996). The four main oil basins currently under production are the Magdalena Medio Valley (MMV), Upper Magdalena Valley (UMV), Llanos Orientales (LL), and Putumayo (PM) (ANH, 2011; ANH and Mejia, 2019). (Yáñez et al., 2019) identified 13 potential oil fields in Colombia suitable for EOR with CO_2 (CO_2-EOR), based on their MMP and with a minimum of 50 MMbbl of OOIP (see Table 2). This group of candidate oil fields showed an additional oil recovery potential of 807 MMbbl and a storage capacity of 248 $MtCO_2$, and are mainly located in the MMV basin near the largest oil refinery in Colombia (see Fig. 3).

3.3. Matching

Four potential clusters for potentially deploying CO_2-EOR projects in Colombia were identified, based on the location of the CO_2 industrial sources and suitable oil fields within a range of 300 km (see Fig. 3).

Cluster 1 comprises the most significant number of CO_2 sources and suitable oil fields for CO_2-EOR, and is located in the MMV around the largest oil refinery. Cluster 2 is a CO_2-EOR niche, with CO_2 being potentially provided from CO_2-natural gas separation during gas extraction operations, which would be injected close to the production wells in the same region. The second-largest source of CO_2 in the inventory (Cartagena Refinery, Reficar) is grouped in Cluster 3, with significant emission sources from the cement and power generation industries. Despite a significant number of CO_2 sources being identified in this cluster, only one oil field was found to be suitable for CO_2-EOR. Cluster 4 is defined by 6 out of 7 bioethanol production plants and the largest cement factory in the country, with three suitable oil fields for CO_2-EOR.

As defined in Section 2.3 of the methodology, all identified sources are near a trunk of the gas pipeline infrastructure which can eventually facilitate CO_2 transport (see Fig. 3). Potential CO_2 sources and oil fields, as identified by cluster, are provided in Appendix 7.9.

3.3.1. Cluster 1

This cluster has a CO_2 capture potential of 4.3 $MtCO_2$/year from the oil, power generation, and cement industries. In addition, this region shows a storage potential of approximately 200 $MtCO_2$. This means the captured CO_2 could potentially be injected for approximately 50 y.

In the largest refinery (R1), only two out of the four cracking units were considered as potential CO_2 sources. This decision was made because one unit operates solely as a backup, indicating a low capacity factor and intermittency in operation. Another unit (the R1-FCC-3) unit is quite old, and does not offer sufficient conditions for proposing a retrofitting project. The CO_2 emissions from the H_2 production plants in R1 are the low-hanging fruit to be captured. Although the capture process releases a high concentration of CO_2 (> 95 %) at slightly above atmospheric pressure, the CO_2 volume is low (63 $ktCO_2$/year). Approximately 45 % of the CO_2 emitted in the refinery's power generation plants (furnaces, heaters, boilers) was considered as a potential source for capture. This CO_2 comes from two central cogeneration units. Other units are scattered within the refinery and show irregular operation, and are therefore considered less suitable for CC.

In the cluster, there are three suitable oil fields for CO_2-EOR in a radius of less than 12 km from R1, with a storage potential of 110 $MtCO_2$. However, the CO_2 availability is only sufficient for injection into the two closer oil fields. It is proposed to use CO_2 from the refinery in oil field H, and then with a second project, inject CO_2 captured at the power and cement plants into the oil field A. The cement and power plants within a 200 km radius of the refinery were included, and are also located very close to the trunk gas pipeline network. This infrastructure would ease the development of a CO_2 transport pipeline.

Following the criteria presented in the methodology, the ranking of CO_2 sources and the suitable oil fields from Cluster 1 are provided in Table A4 and A5 in Appendix 7.10. CCS-EOR projects aim to inject the maximum amount of CO_2 possible in the fields to achieve the highest storage potential and significant oil recovery, as proposed for advanced EOR operations by (IEA, 2015a). The first two oil fields in the ranking were chosen to assure the highest possible CO_2 injection flow with regard to the storage capacity, which allows a typical project time (approximately 25 y), and because of their location, which reduces transport costs. This selection means that with these two fields (H, A), there is a storage potential of 107 $MtCO_2$ when using the sources of the refinery, cement, and power plants for Cluster 1, as shown in Table 8.

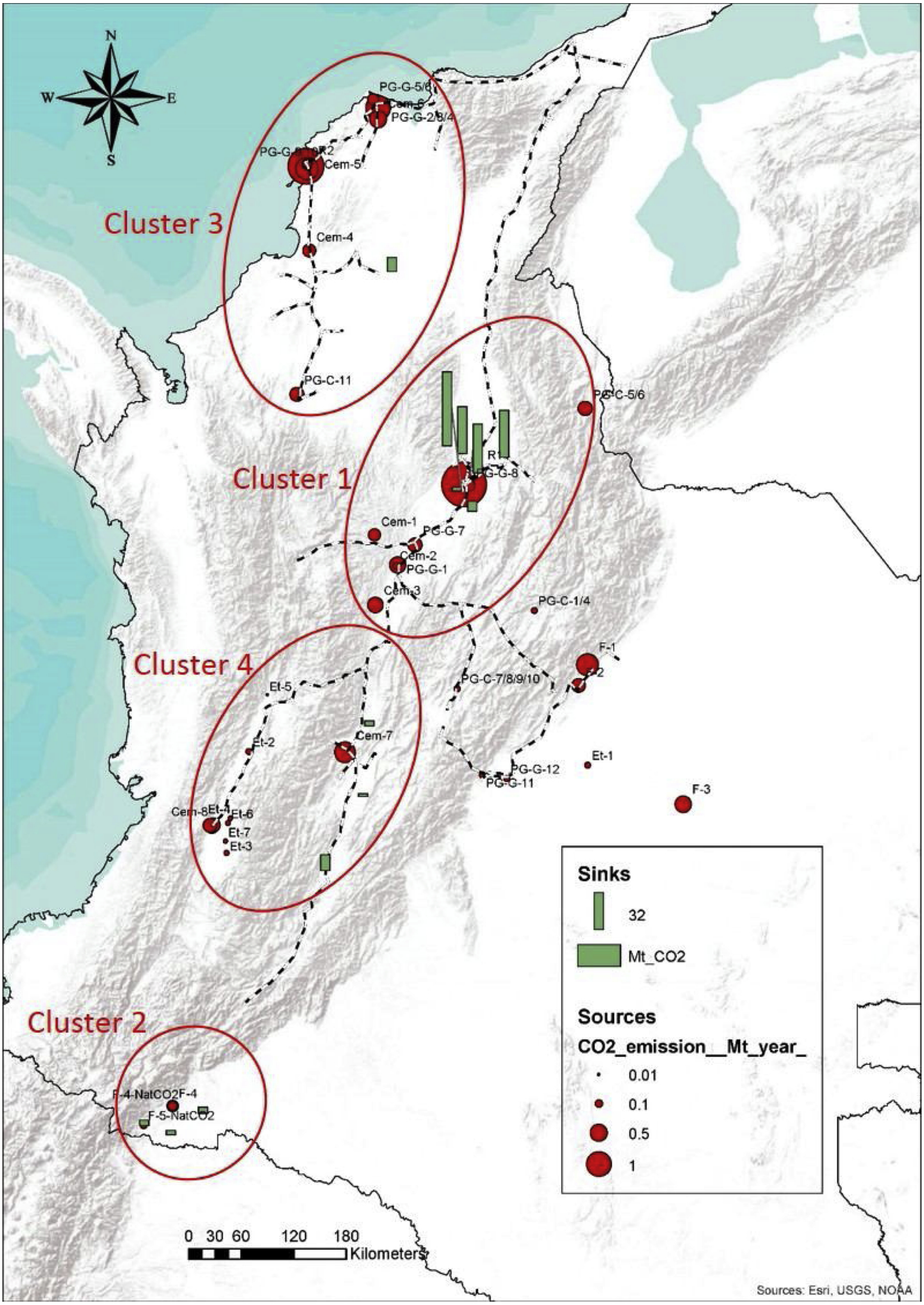


Fig. 3. Cluster of CO_2 sources and sinks for CO_2-enhanced oil recovery (EOR) projects in Colombia. (Dashed lines depict trunk gas pipeline infrastructure.).

3.3.2. Cluster 2

This group includes two oil fields which currently produce a stream of CO_2 (70–75 %) associated with oil production. There are also two potential fields in this cluster suitable for CO_2 injection in an EOR process. Currently, CO_2 is vented to the atmosphere. Although the CO_2 volume is relatively low, the interest lies in the proximity between

Table 8
Summary of matching cases proposed for CO_2-EOR in Colombia.

Match	Source	Sink (Oil Field)	CO_2 to inject [Mt/year]		CO_2 Storage Capacity [$MtCO_2$]	Oil recovery Potential [MMbbl]
C1-M1	R1-H2-1	H	0.04	2.77	64	219
	R1-H2-2		0.02			
	R1-HDT-1		0.08			
	R1-FCC-2		0.32			
	R1-CHP-1		0.65			
	R1-FCC-1		0.27			
	R1-CHP-2		0.12			
	R1-HDT-2		0.92			
	R1-HCK-1		0.18			
	R1-DCK		0.18			
C1-M2	PG-G-8	A	0.20	1.56	43	145
	PG-G-7		0.31			
	Cem-2		0.07			
	Cem-3		0.35			
	PG-G-1		0.42			
	Cem-1		0.21			
C2	F-4-NatCO2	M, O, Q	0.15	0.22	14	36
	F-5-NatCO2		0.07			
C3	R2-HDT-1	B	0.04	0.51	12	41
	R2-H2-1		0.03			
	R2-HCK-1		0.03			
	R2-FCC-1		0.21			
	R2-CHP-6		0.19			
C4	Cem-7	K, N, P	0.61	0.87	21	62
	Et-2		0.06			
	Et-3		0.05			
	Et-4		0.05			
	Et-5		0.02			
	Et-6		0.04			
	Et-7		0.04			
Total			**5.9**	**5.9**	**154**	**503**

source and sink (less than 40 km), and the relative ease of the capture process (recovery of condensable hydrocarbon is needed to increase the CO_2 purity). It is proposed to integrate the sources and sinks in a single EOR project owing to their proximity, the CO_2 volume available, and the estimated storage capacity. The results of ranking the CO_2 sources and suitable oil fields from Cluster 2 are provided in Tables A6 and A7.

3.3.3. Cluster 3

Cluster 3 covers one of the most important industrial centres of the country, given its location on the north coast, close to the largest Colombian seaports. This industrial hub includes the second-largest refinery, the largest cement plant, and approximately 50 % of the nation's thermal generation capacity for electricity. These sources represent a captured CO_2 volume of approximately 5.4 $MtCO_2$ per year, of which only 11 % comes from the refinery R2. These industrial sources are located close to the main gas pipeline and report a high processing capacity and therefore, a significant volume of emissions.

Despite the significant volume of CO_2 available, only a single field (oil field B) near this hub was identified as suitable for CO_2-EOR. It was located at a distance of less than 300 km, per the threshold suggested by (Bachu, 2016).

Similar to the case with refinery R1, the 'low-hanging fruits' of the CO_2 sources in this cluster are in the hydrogen plants. However, owing to their low volume, other sources are required, such as cracking, hydrocracking, and cogeneration units. Owing to the lack of suitable oil fields for CO_2-EOR and giving priority to the sources in the oil sector, in this cluster, only the CO_2 sources at the refinery were used for the matching exercise. The results of ranking the CO_2 sources and suitable oil fields from Cluster 3 are provided in Tables A8 and A9 in Appendix 7.10.

3.3.4. Cluster 4

Cluster 4 is located in the southwest of the country, and seeks to inject the oil fields of the UMV basin. This region has three oil fields suitable for CO_2 injection, which are close to two cement plants, two thermoelectric plants, and six sugarcane-based ethanol plants.

This region includes the second-largest cement plant, and is relatively close to the bioethanol producing region of Colombia. CO_2 from fermentation processes is particularly interesting, as it releases high-purity CO_2 (> 95 %) while reducing capture costs.

Three suitable oil fields for CO_2-EOR are located in this cluster, with a potential storage capacity of 21 $MtCO_2$. Although this cluster includes six out of the seven bioethanol production plants in the country, the CO_2 capture potential is low (at approximately 27 %), for a total of 0.98 Mt/year for this region. Also, these plants are not close to the potential sinks, at distances of approximately 100–300 km.

The cement plant has a significant volume of CO_2 available, and is also at a closer distance, i.e. approximately 50 km from the identified injection fields. This raises two potential scenarios or matches in this cluster. The first one would use only the CO_2 captured in the cement plant, and the second would integrate the bioethanol plants to the already-established project, increasing the quantity and quality of the available CO_2. The results of ranking the CO_2 sources and suitable oil fields from Cluster 4 are provided in Tables A10 and A11.

A total storage capacity of 154 $MtCO_2$ and oil recovery potential of 503 MMbbl is estimated from the matches selected for potential CCS-EOR projects in Colombia (see Table 8). Fig. 4 depicts the CO_2 sources and oil fields identified for the CCS-EOR projects, and indicates potential CO_2 transport pipelines for the proposed matches.

Fig. 5 shows the CO_2 capture potential of matched cases, as compared to the emissions inventory prepared in this study, and that of the national government for each sector. The matched CO_2 capture potential is estimated at 5.9 $MtCO_2$, representing approximately 32 % of the emissions inventories (18 $MtCO_2$).

In this study, capture potentials of 78 %, 58 %, 26 %, and 13 % were identified for the total CO_2 emissions identified from the ethanol, oil, cement, and power generation industries, respectively.

The matched capture potential for the power generation industry is the lowest by sector, despite having the highest CO_2 emissions and lower capture costs. In that regard, the power plants are mainly located in the mountains and on the northern coast far from the oil fields, making them unfeasible. In total, there is a CO_2 capture potential of 5.9 $MtCO_2$/year for the matching cases. This potential CO_2 supply would be provided as 59 %, 21 %, 16 %, and 4 % from the oil, cement, power, and ethanol industries, respectively. The petroleum industry supplies most of the CO_2 required for EOR for the selected oil fields, which can be explained by the preference given to oil point sources. However, despite the significant emissions, 40 % of the CO_2 must be supplied by other sectors.

3.4. Potential for EOR and CO_2 storage

3.4.1. CO_2 storage

Fig. 6 depicts the CO_2 storage potential, as estimated for cluster and sector. The most significant storage potential was found in Cluster 1 with 107 $MtCO_2$, representing 70 % of the total national capacity, followed by Cluster 4 (13 %), and finally Clusters 2 and 3 (9 % and 8 %, respectively). Cluster 1 also included emissions from the refinery R1, which is the largest industrial source of CO_2. Detailed data is presented in Appendix 7.11 (Table A12).

Under the proposed scenarios, it would be possible to capture and inject 3.5 $MtCO_2$/year (approximately 90 $MtCO_2$ in 25 y) from the oil industry, which represents 41 % of the CO_2 emissions from the national oil company in 2016. Despite the significant potential for CO_2 capture in the cement and power generation industries, its use is limited by the lack of geographically-suitable fields.

3.4.2. Incremental oil recovery

Fig. 7 shows the additional oil recovery expected by cluster and sector. Similar to the storage capacity, Cluster 1 has the most significant

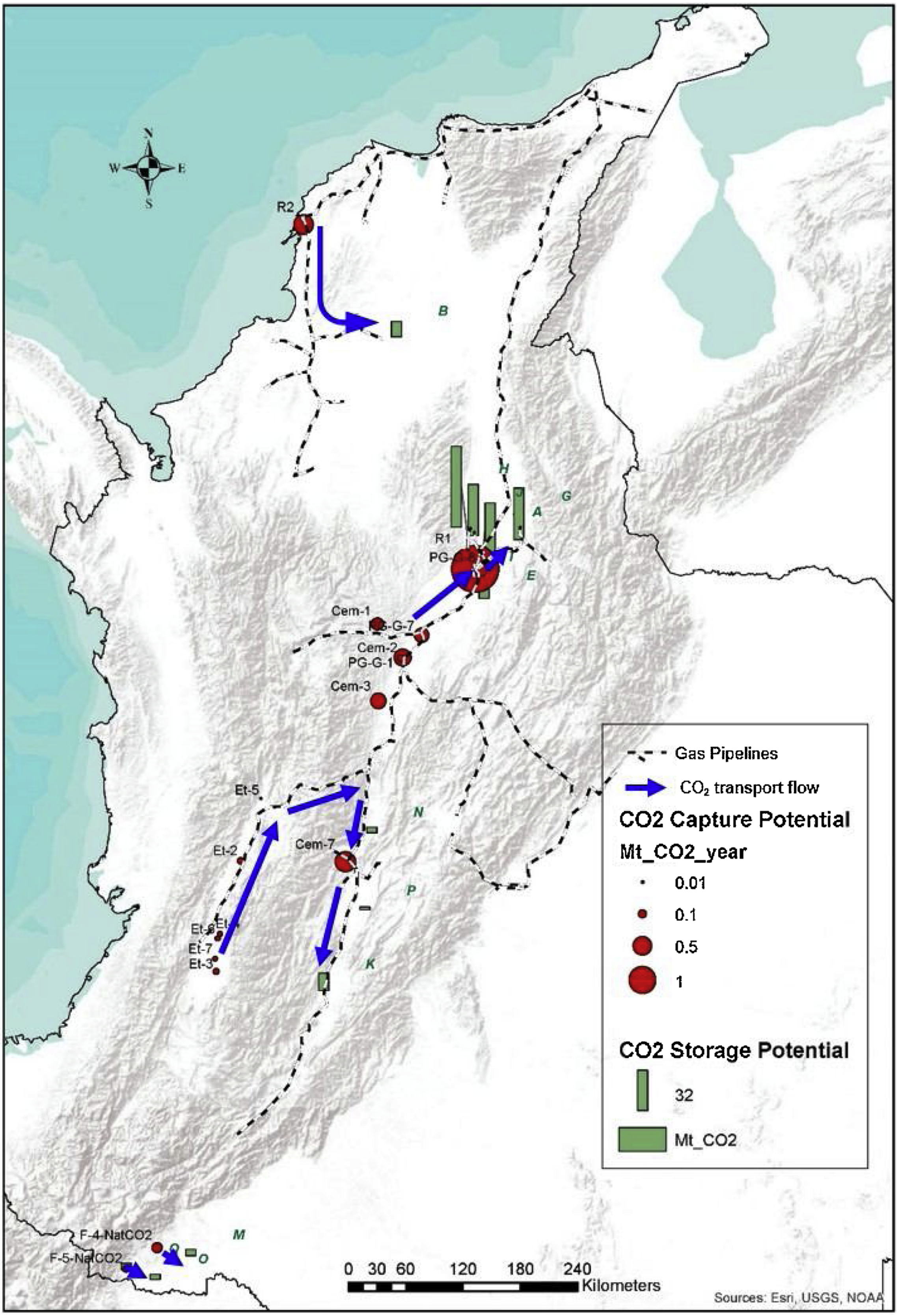


Fig. 4. Selected CO_2 industrial sources and oil fields for potential CO_2-EOR projects in Colombia.

oil recovery potential, with approximately 360 MMbbl. In total, the additional oil recovery potential was estimated as 487 MMbbl. The cement sector is the second-largest industrial source of CO_2 for the CO_2-EOR. Detailed data is presented in Appendix 7.11 (Table A13).

3.5. Economic analysis

3.5.1. CO_2 capture

Fig. 8 shows the specific CO_2 capture cost for the selected emitter

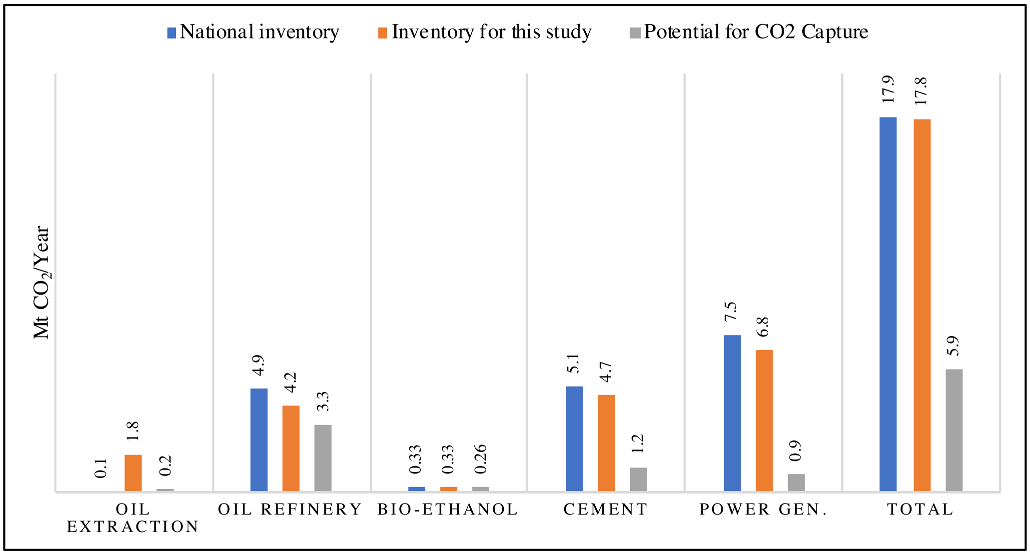


Fig. 5. CO_2 capture potential by sector compared to the estimated emissions by the inventory.

points, as a function of the annual capture potential. Breakdowns of this cost and other key performance parameters in CO_2 capture are presented in Table 9.

The largest CO_2 volumes were found in refinery R1. The fluid catalytic cracking (FCC) and CHP processes, with low CO_2 concentrations (4%–16%), are the most significant sources at the refinery (approximately 80 % of the refinery CO_2 emissions), and represent 49 % of the capture potential for R1. The hydrotreatment (HDT), steam methane reformer (SMR), and hydro-cracking (HCK) processes show higher CO_2 concentrations, between 40 % and 95 % CO_2. These streams might account for approximately 50 % and 21 % of the CO_2 capture potentials for R1 and R2, respectively.

The lowest CO_2 capture costs were calculated at the bioethanol plants, oil production wells, and hydrogen production processes. These emitter points resulted in an average cost of 16 €/tCO_2, with a low capture potential of approximately 0.5 MtCO_2/year. Nevertheless, the HDT, FCC, and CHP processes at refinery R1 represent the largest CO_2 capture potential, with 2.6 MtCO_2, and a cost of 130 €/tCO_2. Other sources from the refinery R1 and refinery R2 result in higher capture costs, mainly owing to the low volumes available.

The CO_2 capture cost at refineries decreases below 130 €/tCO_2 for volumes above 1.2 Mt/year. Meanwhile, power generation shows a similar cost, with just 0.2 Mt/year. The cement sector, however, requires approximately 0.6 Mt/year to obtain a similar capture cost.

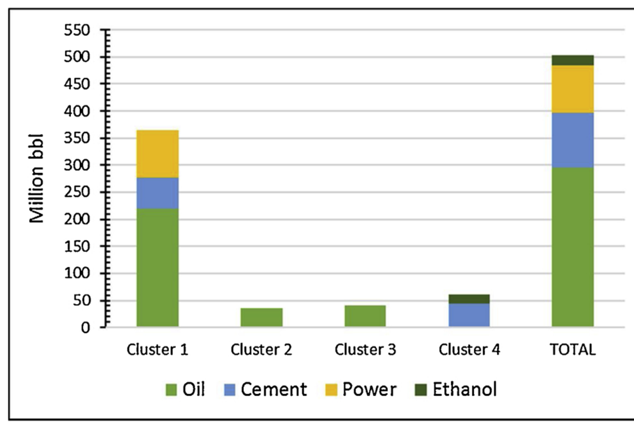


Fig. 7. Breakdown of the incremental oil recovery potential based on the CO_2 supplied by sector and clusters for CCS-EOR in Colombia.

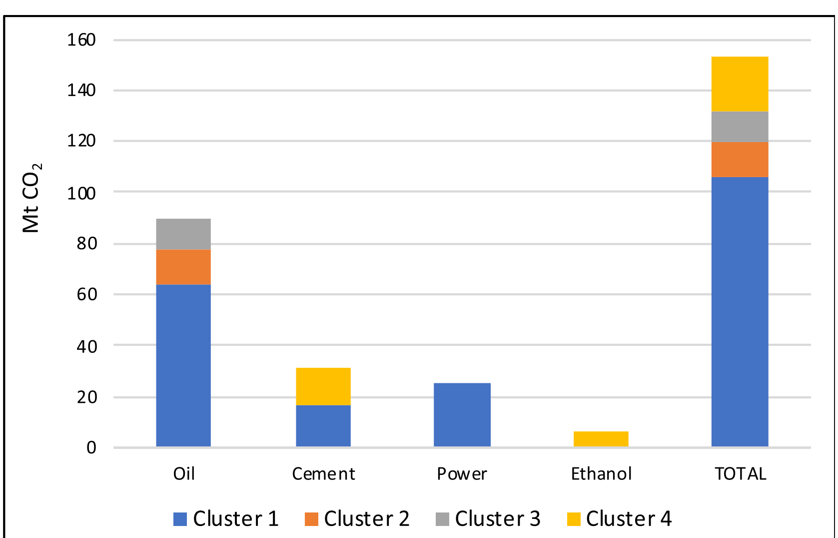


Fig. 6. Breakdown of the CO_2 storage potential by sector and clusters for carbon capture and storage (CCS)-EOR in Colombia.

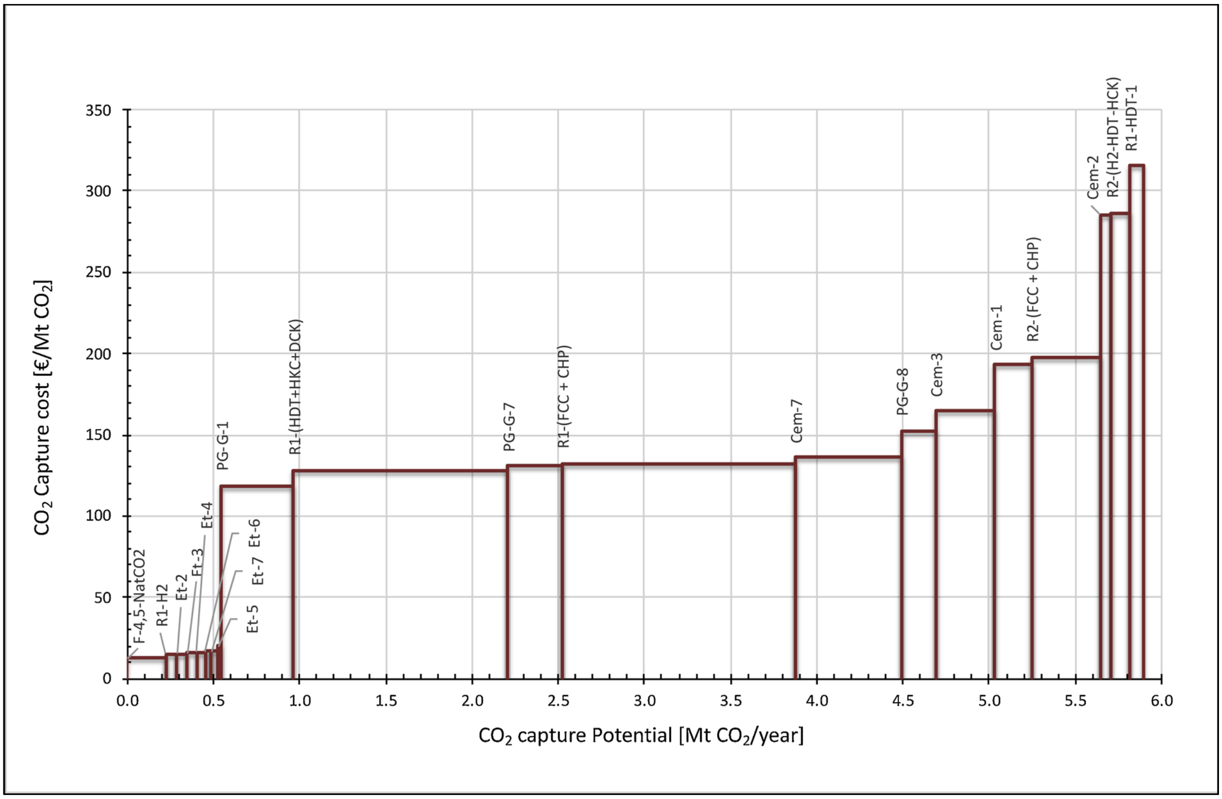


Fig. 8. CO_2 capture cost from potential sources.

Table 10 depicts the levelised capture cost for the aggregate CO_2 capture used for every cluster identified.

3.5.2. CO_2 transport

The layout of the CO_2 transport pipelines is shown in Fig. 9, and follows (where possible) the same corridors as existing natural gas pipelines. This assumption means the same rights-of-way (ROWs) could be used, and that it would be technically feasible to build such infrastructure.

Table 11 provides a summary of the transport costs per pipeline section for each cluster. The cost of transport in Cluster 4 was calculated as the sum of two pipeline sections. The first section includes CO_2 transport from the group of ethanol plants toward the emitter point Cem-7. The second section is comprised of a network between oil fields N, P, and K and Cem-7, considering the total amount of CO_2 to transport in Cluster 4. Cluster C1-M2 used a similar approach to Cluster 4, i.e. defining six sections, as presented in Table 11. In contrast, Cluster C2 considered a single pipeline connecting the selected oil fields to the sources. In this case, owing to the relatively low amount of CO_2, an independent pipeline would significantly increase the investment cost.

The CO_2 transport costs provided in Table 11 do not include compression costs, as these are included in the capture costs. Cluster 1 presents the most favourable conditions with the least distance to transport the largest volume of available CO_2, leading to the lowest levelised cost of 0.6 €/tCO_2. As distance increases from Clusters C2, C3, and C4, the cost increases up to 23 €/tCO_2. However, Cluster C1-M2, with an average distance but moving 1.5 MtCO_2/year, achieves a levelised cost of 8 €/tCO_2.

It should be noted that the cost of transport pipelines includes a terrain factor as defined by (Knoope et al., 2014), which considers whether the pipeline crosses densely- or lightly-populated areas. However, topographic conditions not considered in this study, such as those observed for Clusters C1-M2 and C4, may affect the estimates of the specific transportation costs to a greater extent.

3.5.3. CO_2 cost in EOR operations

Fig. 10 shows a breakdown of the CO_2 costs for the main steps of EOR operations, such as CO_2 injection, gas production associated with gas, and CO_2 recycling. The share of the levelised CO_2 cost (expressed in €/tCO_2) per step in the EOR process varies significantly for each case. However, the injection process accounts for most of the cost. When considering the deployment of all projects (shown as TOTAL in the figure), injection operations represent approximately 55 % of the levelised cost, whereas the recycling and production costs are distributed relatively equally.

The results obtained from the techno-economic analysis of EOR operations are shown in Table 12. A summary of the costs per oil field and the global costs for Clusters 2 and 4 are also included in this table, as these groups include several oil fields suitable for injecting CO_2. In addition to the increase of storage capacity, synergies can also occur, as in Cluster 2. This group has an alternative option of injecting all the CO_2 captured in the region only in the oil field M. This option maintains the same storage capacity provided by the group, but reduces the levelised CO_2 cost by approximately half, at 34 €/tCO_2.

The CO_2 injection cost depends mainly on the number and depth of the injection wells considered in each case. The number of injection wells is determined a priori, based on an injection pattern defined for the EOR project and the number of production wells. However, this pattern and other operational parameters are part of the injection strategy of the project, which might change depending on the operator and the aim(s) set for each project or recovery stage.

There are reservoir-specific parameters from the EOR operations affecting the associated costs. As an example, C1-M1 presents the highest levelised CO_2 injection cost with 38 €/tCO_2, and in contrast, the C1-M2 estimate is merely 8 €/tCO_2. The difference is owing to the size and development of the oil fields. The first field includes 296 production wells, whereas the second includes 35 wells; meanwhile, the storage capacity is 60 % higher in the first oil field. However, both oil fields present approximately the same depth, which could also affect

Table 9
Key performance data of CO_2 capture for the industrial emitter points.

Sector	Process unit [l]	Capture Technology	Capture efficiency [%CO_2]	CO_2 Captured [MtCO_2/year]	Capex [a, b] [M€,2017]	Opex [M€,2017]	CO_2 Capture Cost [L] [€,2017/tCO_2]	Reference
Oil Refinery [k, n]	R1-(FCC + CHP) [e]	Post-combustion-MEA	90 %	1.35	€ 1,335	€ 68	€ 132	(IEAGHG, 2017)
	R1-HDT-1 [f]	Post-combustion-MEA	90 %	0.08	€ 189	€ 10	€ 316	
	R1-(HDT + HCK + DCK) [g], [m]	Post-combustion-MEA	90 %	1.24	€ 1,185	€ 61	€ 128	
	R1-H2 [h]	n.a	100 %	0.06	€ 3	€ 1	€ 15	(Knoope et al., 2014)
	R2-(HDT + H2 + HCK) [i]	Post-combustion-MEA	90 %	0.11	€ 231	€ 12	€ 286	(IEAGHG, 2017)
	R2-(FCC + CHP) [j]	Post-combustion-MEA	90 %	0.40	€ 588	€ 30	€ 198	
Oil Extraction	F-4,5-NatCO_2	n.a.	100 %	0.22	€ 6.8	€ 1.9	€ 12	(Knoope et al., 2014)
Power generation	PG-G-1	Post-combustion-MEA	91 %	0.42	€ 212	€ 14	€ 119	(IEAGHG, 2018a)
	PG-G-7	Post-combustion-MEA	91 %	0.31	€ 174	€ 12	€ 131	
	PG-G-8	Post-combustion-MEA	91 %	0.20	€ 128	€ 9	€ 152	
Cement [c]	Cem-1	Post-combustion-MEA	85 %	0.21	€ 207	€ 14	€ 193	(Kuramochi et al., 2012)
	Cem-2	Post-combustion-MEA	85 %	0.07	€ 94	€ 7	€ 285	
	Cem-3	Post-combustion-MEA	85 %	0.35	€ 288	€ 20	€ 164	
	Cem-7	Post-combustion-MEA	85 %	0.61	€ 423	€ 30	€ 136	
Ethanol [d]	Et-2	n.a	100 %	0.06	€ 2.9	€ 0.6	€ 15	(Knoope et al., 2014)
	Et-3	n.a	100 %	0.05	€ 2.7	€ 0.5	€ 16	
	Et-4	n.a	100 %	0.05	€ 2.4	€ 0.4	€ 16	
	Et-5	n.a	100 %	0.02	€ 1.2	€ 0.2	€ 20	
	Et-6	n.a	100 %	0.04	€ 2.2	€ 0.4	€ 17	
	Et-7	n.a	100 %	0.04	€ 2.2	€ 0.4	€ 17	

[a] A scale factor of 0.7 was used for the cost estimation in the oil industry, and of 0.67 for the cement and power generation industries.
[b] Capital expenditure (Capex) is expressed as total capital requirement (TCR). Standard percentages were used to account for indirect costs. TCR = 110 % total plant cost (TPC); TPC = 130 % process plant cost (PPC). PPC comprises equipment and installation costs. TPC comprises PPC and engineering fees and contingencies. TCR comprises TPC, owner costs, and interest during construction. (Berghout et al., 2013).
[c] The energy required for the post-combustion process is produced through an onsite coal combined heat and power (CHP) + CO_2 capture.
[d] No capture technology is needed, as CO_2 is produced at a high concentration (greater than 95 %), and it is assumed that no treatment other than compression is required. Capex and Opex are estimated as compression and pumping costs.
[e] It was assumed a post-combustion capture in a combined stack for CHP and fluid catalytic cracking (FCC), as suggested by the International Energy Agency - Greenhouse Gases (IEAGHG, 2017). This system includes the following process units: R1-FCC-1, R1-FCC-2, R1-CHP-1, and R1-CHP-2.
[f] CO_2 is captured from flue gas in the steam methane reformer-pressure swing adsorption (SMR-PSA) process at atmospheric conditions.
[g] CO_2 is captured from a combined stack for new projects at refinery 1: R1-HDT-2 + R1-HCK-1 + R1-DCK.
[h] No capture technology is needed, as CO_2 is produced at a high concentration (greater than 95 %) and it is assumed that no treatment is required but compression. CO_2 is captured in a combined stack from R1-H2-1 + R1-H2-2.
[i] CO_2 is captured from flue gas in a combined stack from R2-HDT-1 + R2-H2-1 + R2-HCK-1.
j A post-combustion capture was assumed, in a combined stack for CHP and FCC as suggested by (IEAGHG, 2017). This system includes the following process units: R2-FCC-1 + R2-CHP-6.
[k] CO_2 from the additional CHP plant is not captured. However, the total cost of the equipment are included in this study.
[L] This cost includes the capture and compression costs.
[l] Process unit code: R: Refinery; H2: Hydrogen production; HDT: Hydrotreatment plant; FCC: Fluid Catalytic Cracking; CHP: Cogeneration; HCK: Hydrocracking; DCK: Delayed coker; F: Upstream Facility; TC: Turbo-compressors; TG: Turbo-powers; FH: furnace/Heater; ICE: internal combustion engine; Bo: Boiler; NatCO_2: Natural CO_2 source; Et: Ethanol; Cem: Cement; PG: Power generation; G: gas-fired; C: Coal-fired; O: Oil-fired.
[m] Projects in development.
[n] The cost of CO_2 capture is based on the retrofitting estimation cost by (IEAGHG, 2017) for a medium-high complex refinery. This additional cost includes the implementation of CO_2 capture (i.e. the costs of CO_2 capture, conditioning, compression, and additional CHP), as well as refinery modifications (e.g. moving of tanks) and interconnections.

Table 10
Key parameters of CO_2 capture cost for the selected matched cases.

Match	CO_2 emitter points (Sources) [1]	CO_2 Captured [Mt CO_2/year]	Capex [2] [M€]	Opex [2] [M€]	Levelised CO_2 capture cost [3] [€/t CO_2]
C1-M1-1	Refinery R1	2.74	€ 2,712	€ 140	€ 133
C1-M1-2	PG-G-1,PG-G-7,PG-G-8,Cem-1,Cem-2,Cem-3	1.56	€ 1,102	€ 76	€ 153
C2	F-4,5-NatCO2	0.22	€ 7	€ 2	€ 12
C3	R2-(H2-HDT-HCK),R2-(FCC + CHP)	0.51	€ 789	€ 41	€ 209
C4	Cem-7,Et-2,Et-3,Et-4,Et-5,Et-6,Et-7	0.87	€ 437	€ 32	€ 101
TOTAL		**5.90**	**€** 5,046	**€ 290**	€ 159

[1] CO_2 emitter points referred to the industrial sources included for every cluster as a CO_2 supplier for the EOR project. It must be noted that CO_2 flow is a cluster-specific constraint either by the industrial sources side or by the reservoirs demand for EOR. Process unit code: R: Refinery; H2: Hydrogen production; HDT: Hydrotreatment plant; FCC: Fluid Catalytic Cracking; CHP: Cogeneration; HCK: Hydrocracking; DCK: Delayed coker; F: Upstream Facility; TC: Turbo-compressors; TG: Turbo-powers; FH: furnace/Heater; ICE: internal combustion engine; Bo: Boiler; $NatCO_2$: Natural CO_2 source; Et: Ethanol; Cem: Cement; PG: Power generation; G: gas-fired; C: Coal-fired; O: Oil-fired.

[2] Capex and Opex for every cluster is the result of adding the individual capital investment and operation cost, respectively, required to CO2 capture for every specific emitter point.

[3] The levelised CO_2 capture cost was calculated following Eq. 3.

the injection cost.

The production costs also depend on the number and depth of the wells. However, as shown for the EOR cost model in Appendix 7.6 (Eqs. (16) and (22)), the costs of injection wells are much higher than those of production wells, with an approximate ratio of 1:12. For this study, the C2-O and C2-Q cases showed the highest CO_2 levelised production cost at approximately 15 €/tCO_2, owing to the low volume of CO_2 injected in the project, and for these cases, not related to the number or the depth of the wells. The cost of recycling is related to the size of the separation and compression equipment, which depends on the volume of CO_2 to be recycled, which in turn is a function of the amount of CO_2 injected. C1-M1 presents a higher Capex on the recycling process, but owing to the amount of CO_2 injected, the C2 cases report the highest levelised recycling cost, at approximately 30 €/tCO_2.

3.5.4. Business cases for carbon capture and storage (CCS)-EOR

Fig. 11 and Table 13 provide a summary of the levelised costs for CO_2 in the capture, transport, and EOR stages for the selected cases. From the figure, it can be seen that the highest share of the levelised cost by far is for the CO_2 capture process, representing approximately 70 % of the total cost in the CCS-EOR projects. The higher levelised cost of CO_2 comes from the increase in capture costs calculated for the CO_2 sources in the refinery R2, which has low capture volumes.

Clusters that involve CO_2 capture in the refinery processes present the largest Capex and the highest levelised cost of CO_2 for CCS-EOR, with values above 171 €/tCO_2.

The economic analysis of the identified matches, which were normalised to injection periods of 25 y in EOR operations, estimated a CO_2 storage potential of 142 MtCO_2, and an additional oil recovery of 465 MMbbl.

Fig. 12 compares the CO_2 cost for each stage of the CCS – EOR projects identified by cluster. Capex and Opex expressed in € per ton of CO_2 expected to be stored during the entire EOR project. The cost of CO_2 per stage is shown as the levelised CO_2 cost for capture, transport and EOR, respectively. Cluster C1-M1 seems to depict the best techno-economic performance of the identified projects, as it shows medium figures for the Capex and capture cost, but the highest storage potential.

Fig. 13 presents a sensitivity analysis of the profitability of CCS-EOR projects as a function of oil prices and CO_2 credits. The values used for oil prices and CO_2 credits consider a variation of 64–136 $\$_{,2016}$/bbl and 10–140 $\$_{,2016}$/t$CO_2$, respectively, according to a forecast for 2040 by (IEA, 2015b).

From the data in Fig. 13, it is apparent that there are some profitable cases for CCS-EOR projects, despite the high levelised cost of CO_2 throughout the mitigation value chain. With minimum oil prices at approximately 60 €/bbl and CO_2 credits equal or below 40 €/tCO_2, it seems that projects such as C1-M1 can be profitable. With the same scenario of oil prices, the projects C2, C1-M2, and C4 seem to show profitability (without including credits for CO_2).

3.6. CO_2 mitigation potential

The CO_2 mitigation potential of the CCS-EOR projects in Colombia is presented in Fig. 14. This potential is compared with the estimated emissions for the oil and gas sectors for 2010–2040. It was assumed the projects require approximately 5 y for structuring and deployment; therefore, CO_2 mitigation is effective as of 2025.

The mitigation potential for the period 2025–2040 is approximately 78 MtCO_2 when all projects start CO_2 injection in 2025, representing a 24 % reduction as compared to forecast emissions for the oil industry. In a scenario where the CCS-EOR projects begin in 2025 with only the profitable projects (according to Fig. 13), and then in 2030 add the non-profitable projects (assuming they become profitable), the mitigation potential reaches 94 MtCO_2, i.e. approximately 25 % of the total sector emissions.

CCS-EOR projects could mitigate 24 % of the CO_2 emissions for the oil sector in 2030; its emissions are expected to reach a peak in the period of 2010–2040 according to (Uniandes et al., 2014). As compared to the INDC target set by the Colombian government to reduce 20 % of GHG emissions by 2030, CCS-EOR projects could contribute between 6 % and 7 % of the total accumulated emissions by 2040.

4. Discussion

It is important to bear in mind that the CO_2 availability values calculated in this study are based on a specific operational year for the process units. That is, no future analysis of CO_2 emissions from industrial sources was included, which may affect the estimation of the capture volume and modify the potentials for CO_2 storage and oil recovery. The potential profitability of the business cases could also be affected by a change in the merit order during the matching process, as it prioritised emissions from the oil sector during the ranking of CO_2 sources.

Industrial CO_2 emissions in Colombia are strongly concentrated in the central and northern regions. Notably, the north shows significant CO_2 industrial sources from the cement, power generation, and oil industries, accounting for 6.1 MtCO_2/year. By overcoming the relatively high costs, the CO_2 captured in this region could be delivered to the oil fields in the MMV, or even shipped overseas, given its close location to the seaports. The eastern zone is also interesting, owing to the presence of CO_2 sources from the oil industry (approximately 1.8 MtCO_2/year), but also because it is the most promising region in terms of oil

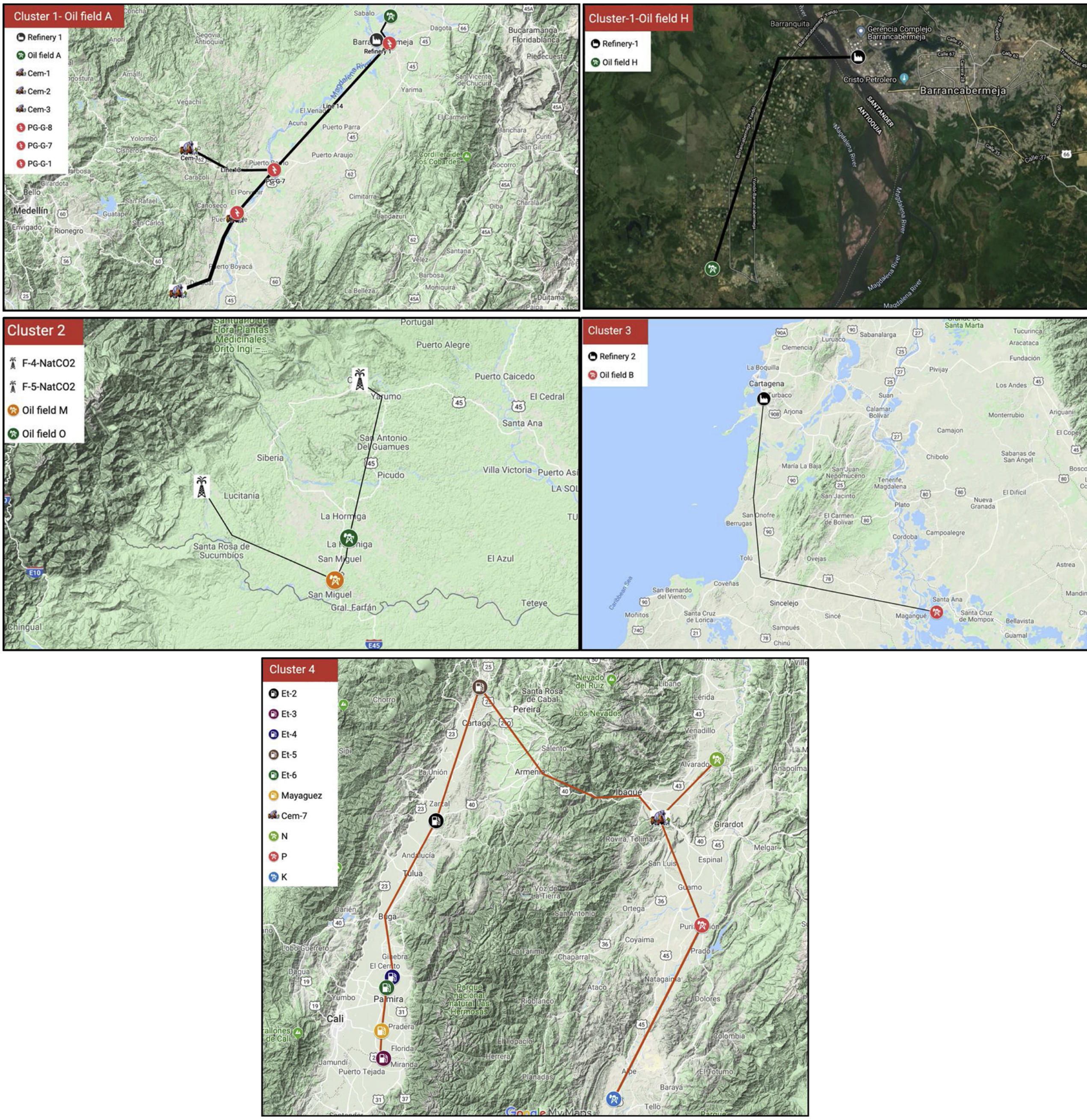


Fig. 9. CO_2 transport infrastructure defined by cluster.

production. However, some technical and economic aspects hinder CCS-EOR development in this region. These aspects include the low American Petroleum Institute (API) gravity of most oil produced (which is not suitable for miscible CO_2-EOR), the fact that the fields are still in primary oil recovery, and because CO_2 transport to the potential EOR regions proves challenging, owing to the mountains.

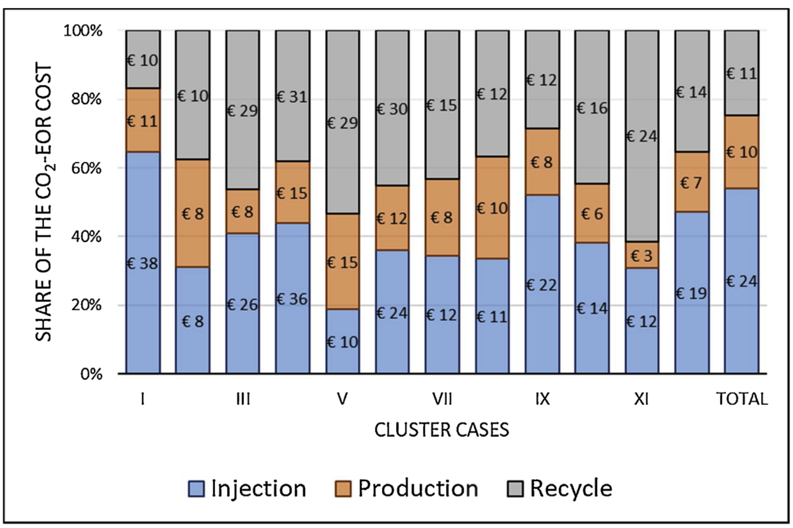
Regarding the cost of CO_2 capture at refineries, it should be noted that a high discount rate of 12 % was used, reflecting specific conditions for Colombia. In contrast, 8 % is usually used in these types of studies for developed countries. Moreover, the CO_2 capture costs used as a reference in this study are higher as compared to other cost estimation studies for this industry. Since there is no new refinery projected to be built in Colombia and the refinery used as a case study is more than 20 years old, we used the latest cost estimation by the IEAGHG, 2017 (Recap project), which focus on retrofitting of CO_2 capture in oil refineries. The higher retrofitting costs estimated in that report are due to the inclusion of the interconnection costs, the installation of an additional CHP plant, cooling water towers and wastewater plant, with significant spare capacity (up to 30 % overdesign). Besides, most of the CO_2 capture cases considered small to medium CO_2 emission point sources with a low to medium CO_2 content in the flue gas ($<=11.3$ %).

The final stage in the CO_2 capture process includes a train of compression, separation, cooling, dehydration, and pumping. As considered in this study and based on (Kuramochi et al., 2012), (IEAGHG, 2018a), and (IEAGHG, 2017), this train increases the CO_2 pressure above the critical point of the fluid (7.4 MPa), and then is pumped to the battery limits of the plant at a pipeline pressure of 11 MPa. In our study, we used a pressure of 13 MPa for the design of the CO_2 transport pipes, according to the value suggested by (Knoope et al., 2014) for the volumes and distances considered in our clusters. This difference represents only a slight variation of up to 0.1 €/tCO_2 for the levelised cost

Table 11
Key parameters of CO_2 transport for the selected matched cases.

Match	Source to sink network	Sink (Oil Field)	CO_2 to inject [Mt/yr]	Length [km]	Capex [M€,$_{2017}$]	Opex [M€,$_{2017}$/yr]	Levelized cost €/tCO_2
C1-M1	R1 to Oil field H	H	2.77	9.2	€ 6.7	€ 0.8	€ 0.6
C1-M2	Cem-3 to Cem-2 (L1)	A	1.56	54.8	€ 11.9	€ 0.3	€ 5.2
	Cem-2 to PG-G-1 (L0)			2.3	€ 1.6	€ 0.1	€ 0.8
	PG-G-1 to PG-G-7 (L2)			30.6	€ 8.8	€ 0.4	€ 1.8
	Cem-1 to PG-G-7 (L3)			49.1	€ 10.5	€ 0.2	€ 7.4 [1]
	PG-G-7 to PG-G-8 (L4)			92.6	€ 32.6	€ 0.8	€ 3.7
	PG-G-8 to Oil field A (L5)			19.1	€ 7.6	€ 0.5	€ 1.0
	Total			248.5	€ 72.9	€ 2.4	€ 7.5
C2	F-4,5-NatCO_2 to oil fields M, O, Q	M, O, Q	0.22	75.7	€ 15.7	€ 0.3	€ 10.5
C3	R2 to oil field B	B	0.51	200.0	€ 53.4	€ 0.9	€ 15.2
C4	Et-2,3,4,5,6,7 to Cem-7 (	K, N, P	0.87	308	€ 71.0	€ 1.1	€ 39.5 [2]
	Cem-7 to oil field K, N, P			194	€ 64.9	€ 1.2	€ 10.9
	Total			502	€ 135.8	€ 2.4	€ 22.5

[1] This pipeline section shows the highest CO_2 specific cost, as it manages the lowest CO_2 volume (0.2 Mt/year) and one of the longest sections (49 km) in Cluster 1.
[2] Similarly to the previous note, this section depicts the highest specific costs per section in Cluster 4. This section transports CO2 from the ethanol plants (0.3 Mt/year) throughout a longer pipeline (with 114 km more), as compared to that from Cem-7 to the oil fields, which supplies the total CO2 volume in the cluster with 0.9 Mt/year.



* Legend in Figure 10 for EOR cases:
I : C1-M1, refers to matching 1 in Cluster 1.
II : C1-M2, refers to matching 2 in Cluster 1.
III, IV, V : C2-CO_2 to M/O/Q and stands for CO_2 injection in the oil fields M/O/Q for Cluster 2, respectively.
VI : C2-CO_2 to M+O+Q, stands for simultaneous CO_2 injection in the oil fields M, O, and Q for Cluster 2.
VII : C2-All CO_2 to M, means the total volume of CO_2 captured in Cluster 2 is injected in the oil field M.
VIII : C3-CO_2 to B, stands for CO_2 injection in the oil field B for Cluster 3.
IX, X, XI : C4-CO_2 to K/N/P stands for CO_2 injection in the oil fields K/N/P for Cluster 4, respectively.
XII : C4-CO_2 to K+N+P stands for simultaneous CO_2 injection in the oil fields K, N, and P for Cluster 4.

Fig. 10. Breakdown of levelised CO_2 cost during EOR operations, expressed as €/tCO_2.
* Legend in Fig. 10 for EOR cases:
I : C1-M1, refers to matching 1 in Cluster 1.
II : C1-M2, refers to matching 2 in Cluster 1.
III, IV, V : C2-CO_2 to M/O/Q and stands for CO_2 injection in the oil fields M/O/Q for Cluster 2, respectively.
VI : C2-CO_2 to M + O+Q, stands for simultaneous CO_2 injection in the oil fields M, O, and Q for Cluster 2.
VII : C2-All CO_2 to M, means the total volume of CO_2 captured in Cluster 2 is injected in the oil field M.
VIII : C3-CO_2 to B, stands for CO_2 injection in the oil field B for Cluster 3.
IX, X, XI : C4-CO_2 to K/N/P stands for CO_2 injection in the oil fields K/N/P for Cluster 4, respectively.
XII : C4-CO_2 to K + N+P stands for simultaneous CO_2 injection in the oil fields K, N, and P for Cluster 4.

of CO_2 transport[5].

Alternatives to CO_2 transport from gas pipelines, such as by truck and through rivers, could be considered — the first when a low volume of CO_2 is available to carry for short distances. Transport along the Magdalena River could be used to connect the industrial centres from the north to the centre region of the country, where the majority of oil fields are located. This option would increase the CO_2 storage and oil recovery potentials in this region, but a technical and economic analysis should be carried out and include different infrastructure (e.g. liquefaction facilities) instead of pipelines.

The CO_2-EOR costs estimated in our study are consistent with the economic model developed by (Fukai et al., 2016), which estimated the feasibility of these project with a CO_2 price of \$40/t and oil prices of \$70 or higher. In EOR projects, the cost of CO_2 is not only owing to the cost of supply but also to the cost of injection, associated oil production, and recycling. The latter requires additional processes for the separation of water, gas, and CO_2 from the crude oil, and finally its compression for reinjection. The costs of CO_2 in EOR operations can vary given the specific conditions of each reservoir, and it is, therefore, difficult to ascertain typical values for each of the stages mentioned above. For this study, there was no allocation of the associated costs for CO_2 and crude; rather, all costs were expressed per ton of CO_2 used. That is, the crude produced was taken as the primary income, along with the credits potentially received for the stored CO_2. Further analyses could consider the allocation of the costs of crude oil production and CO_2 injection when using not only economical, but also environmental criteria.

The operation hours or utilisation factors of each CO_2-emitting plant are operational parameters of great interest when planning an integrated CCS-EOR project. For a constant emission factor and a simultaneous operation of a capture plant, the utilisation factor determines the absolute volume of CO_2

[5] The variable costs for pumping to reach a pressure of 13 MPa instead of 11 MPa are 0.15 €/tCO_2, estimated as follows: (0.44 kW h/tCO_2/MPa × (13 MPa–11 MPa) × 0.22 kgfuel/kWh × 0.7 €/kgfuel). The required design pumping capacity is ((13 MPa–11 MPa)/75%/ 850 kg/m^3 × (2.77×10^6 tCO_2/y/(365 × 24 × 3.6 × 0.85)) 0.5MW and 0.8MW for an outlet pressure of 11 MPa and 13MPa, respectively. The Capex values would be (74.3 × (498/3)0.58 × 30.9 =) 3.9 M€ and 5.2 M€, respectively. This leads to an estimated levelised cost difference of (0.15 €/tCO_2 + (5 M€ − 4 M€) × 11.02%/2.7 MtCO_2/y) 0.1 €/tCO_2.

Table 12
Key parameters of CO_2-EOR operations in the oil fields for the selected matched cases.

Match	Oil field	CO_2 injected [Mt/year]	Capex [c] [M€]	Opex [M€/yr]	Levelized CO_2 cost[a] [€/tCO_2]	Project Lifetime	CO_2 storage potential, [Mt]	Oil Recovery potential, [MMbbl]
C1-M1	H	2.77	€ 412	€ 111	€ 59	23	64	217
CI-M2	A	1.56	€ 86	€ 31	€ 27	25	39	132
C2	M	0.08	€ 25	€ 2	€ 63	25	2	4
	O	0.06	€ 26	€ 2	€ 82	25	2	3
	Q	0.07	€ 16	€ 2	€ 54	25	2	6
	Total (sum)	0.22	€ 67	€ 6	€ 65	25	5.6	14
	All CO_2 to oil field M	0.22	€ 28	€ 4	€ 34	25	5.6	12
C3	B	0.51	€ 44	€ 11	€ 32	24	12	42
C4	K	0.58	€ 54	€ 18	€ 43	24	14	48
	N	0.19	€ 20	€ 4	€ 37	24	4	9
	P	0.11	€ 17	€ 2	€ 39	24	3	5
	Total (sum)	0.87	€ 91	€ 25	€ 41	25	20.9	62
TOTAL [b]		5.9	€ 662	€ 180	€ 45	24	141	465

[a] Levelised cost is calculated with a discount rate of 12 % and for the lifetime of the project.
[b] This scenario assumes projects C1-M1, C1-M2, C2-all CO_2 to M, C3, and C4-total are deployed. The total investment cost is calculated by adding Capex and Opex by project, and then the total levelised CO_2 cost is estimated.
[c] The number of injection wells was calculated based on current production wells in the oil field and using a typical well pattern described by (NETL, 2012), as ten producing wells for every three injectors.

captured, and the total flow of CO_2 available for the project. The former directly affects the marginal cost of CO_2 capture, whereas the latter affects not only the marginal cost of transport, but can also affect the recovery factor and the profitability of the EOR project. This study considered the specific utilisation factor for each industry, and assumed a constant supply for the total CO_2 capture potential. Each industrial sector is associated with a typical utilisation factor, related in this study to aspects such as a) the raw materials supply (e.g. bioethanol production depends on the seasonal sugarcane harvest), b) the market demand (e.g. power generation responds to a merit order defined by a state agency), and c) economic factors (e.g. the oil sector demands high utilisation rates that allow it to reach a financial breakeven point). For the cases described, the utilisation factors are approximately 60 %, 75 %, and 95 %, respectively.

The utilisation factors cannot be standardised for a CCS-EOR project. Each industry responds to its own market and operation dynamics, and not necessarily to the CO_2 demands for storage and oil recovery. Nevertheless, each project should consider the balance with the actual CO_2 supply required by the oil fields where recovery operations are carried out.

In this study, it was assumed that a constant CO_2 flow was delivered to the oil fields during the lifetime of the CCS-EOR project. During an oil recovery project, the gross CO_2 injection flow varies substantially throughout the project, as does the flow of recovered oil and CO_2 produced. In a CCS-EOR project, matching the CO_2 source and the reservoir results on an imbalance of the CO_2 mass flow. This difference is due to the variable CO_2 injection flow demanded in the reservoir and the constant flow captured in the source. The latter responds to an operational and economic criterion that seeks to maximise and maintain the operation hours of the production system, which otherwise would also adversely affect the financial performance of the installed capture technology. To improve the CO_2 balance in the project, King et al., 2013, described a method, which reflects operational conditions used by current CO_2-EOR commercial projects. On this strategy, the injection point moves between wells of the same field, which are in a

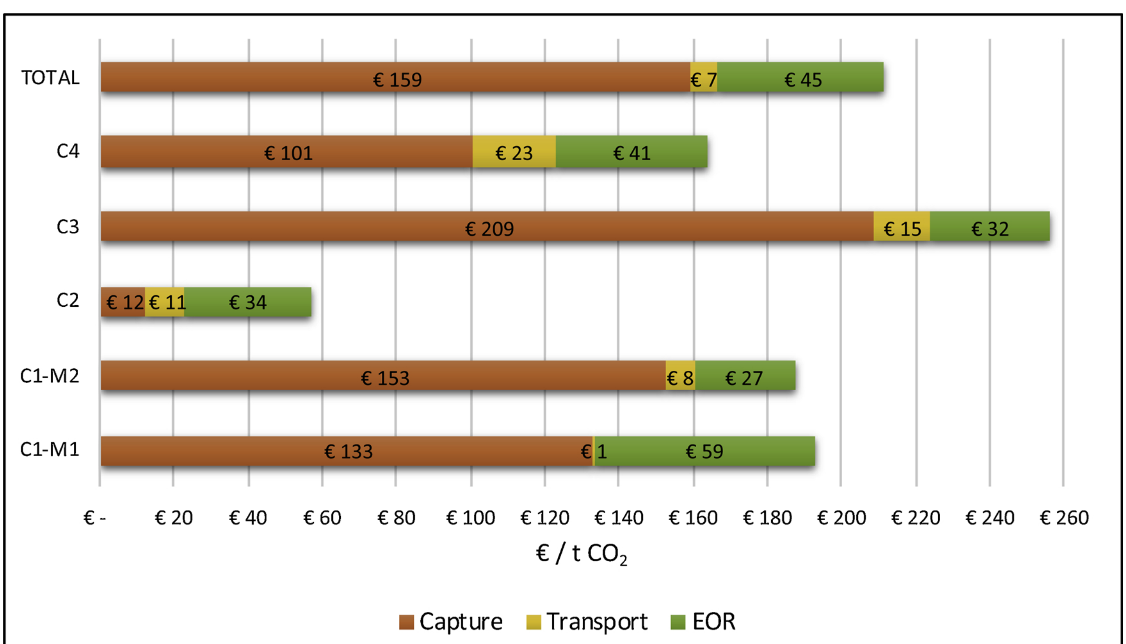


Fig. 11. Breakdown of the levelised cost of CO_2 for potential CCS-EOR projects in Colombia.

Table 13
Key parameters of the carbon capture and storage (CCS)-EOR projects for the selected matched cases.

Match	Capex [M€]	Opex [M€]	Capture cost [1] [€/tCO_2]	Transport cost [2] [€/tCO_2]	EOR cost [3] [€/tCO_2]	CO_2 storage potential, [Mt]	Oil Recovery potential, [MMbbl]
C1-M1	€ 3,131	€ 252	€ 133	€ 0.6	€ 59	64	217
C1-M2	€ 1,261	€ 109	€ 153	€ 7.5	€ 27	39	132
C2	€ 51	€ 6	€ 12	€ 10.5	€ 34	6	12
C3	€ 886	€ 52	€ 209	€ 15.2	€ 32	12	42
C4	€ 663	€ 59	€ 101	€ 22.5	€ 41	21	62
TOTAL	€ 5,992	€ 479	€ 159	€ 7.3	€ 45	142	465

[1] The capture cost refers to the levelised CO_2 capture cost as a whole for the emitter points considered by each cluster, as presented in Table 10.
[2] The transport cost refers to the levelised CO_2 transport cost as a whole for the infrastructure defined each cluster, as presented in Table 11.
[3] The EOR cost refers to the levelised CO_2 cost for the OER operation as a whole for the reservoir included by each cluster, as presented in Table 12.

different injection stage, to guarantee the constant reception of the CO_2 flow captured in the source.

A typical CO_2 recovery project seeks to maximise the CO_2 injection in the first years, and to perform the oil recovery in the shortest possible time. This approach assures a shorter return on investment for better economic performance. This principle, however, does not apply to a CCS-EOR project, which aims to mitigate emissions from industrial sources through the capture and store of CO_2 along a project's lifetime. (King et al., 2013) discussed the economic implications resulting from different flow scenarios for CO_2 injection in a CCS-EOR process. In that work, a fast EOR (peak-shaped CO_2 flow, as in a conventional operation) showed a better NPV than a slow EOR (constant CO_2 flow) when the EOR operation is analysed. Nevertheless, a constant CO_2 flow results in a better NPV when the system-wide usage of CCS-EOR projects was considered.

5. Conclusions

This study developed a technical-economic analysis and provided an inventory of the potential for CO_2 capture in energy-intensive industries, and of its use in oil recovery projects as a strategy for mitigating CO_2 emissions in Colombia. The oil, cement, power generation, and ethanol production industries were selected as potential sources for CO_2 capture and supply for EOR operations, representing approximately 65 % of the emissions of the industrial sector in Colombia.

It was estimated that approximately 18 $MtCO_2$ per year could be considered for capture processes. However, only 5.9 $MtCO_2$ were found feasible for subsequent use in EOR projects. The shares in this potential by sector were 59 %, 21 %, and 16 % for the oil, cement, and power generation industries, respectively. The potentials for CO_2 storage and oil recovery through CCS-EOR were estimated at 142 $MtCO_2$ and 465 MMbbl, respectively. These potentials represent 57 % and 58 % of the CO_2 storage capacity and oil recovery capacity, respectively, as determined by the screening of oil fields in Colombia carried out by (Yáñez et al., 2019).

The CO_2 capture cost is the largest share of the total levelised cost of CO_2 for CCS-EOR projects. This process showed values ranging from 12 €/tCO_2 for the fermentation processes in ethanol production to 209 €/tCO_2 for low-volume sources in the oil refinery. The CO_2 captured in Cluster 2 from associated-gas production with crude oil in the

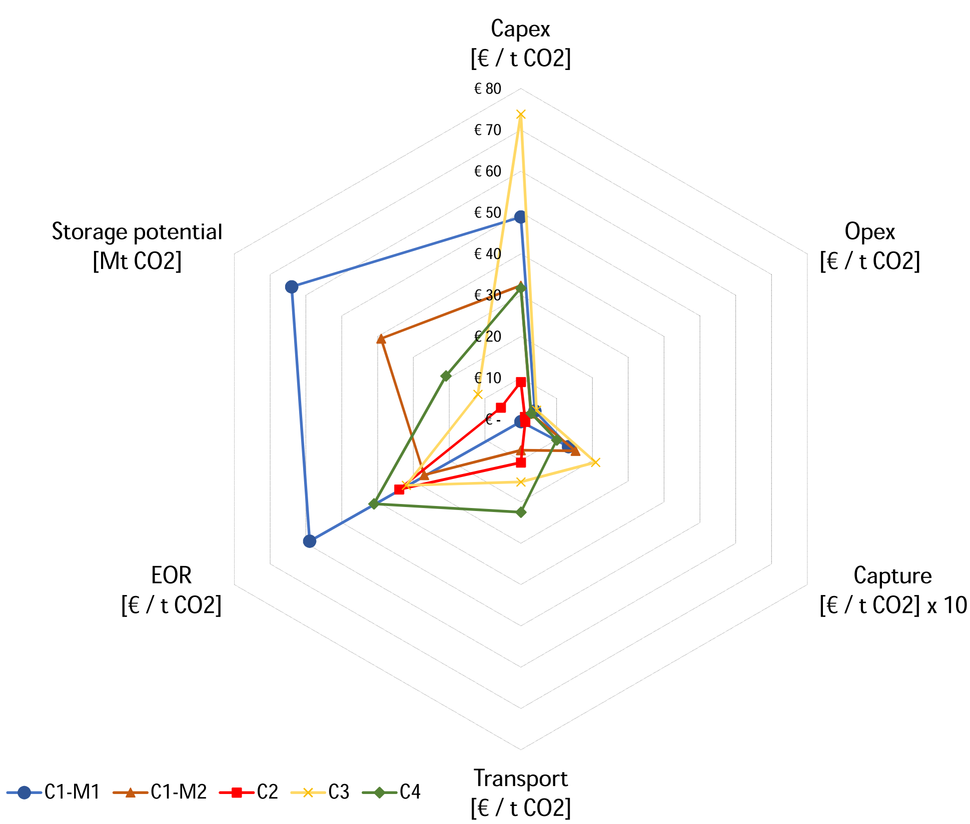


Fig. 12. Comparison of the CO_2 costs per stages in a CCS-EOR integrated project for the identified clusters and their expected storage potential. Capex and Opex were normalised by the CO2 storage potential estimated for each project.

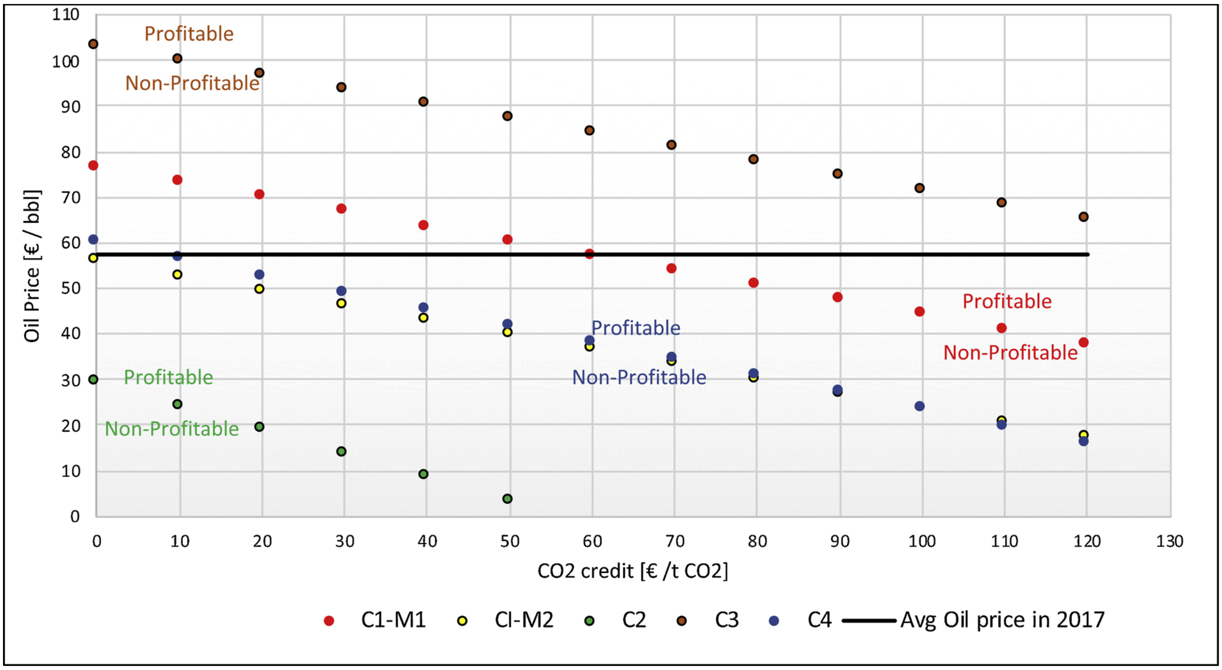


Fig. 13. Profitability analysis of CCS-EOR projects expressed as a function of CO_2 credit and oil price for every cluster. (Every point in the line represents values of CO_2 credit and oil price for a net present value (NPV) value of zero. Profitable conditions (NPV > 0) are estimated above the line, and non-profitable conditions (NPV < 0) beneath it.

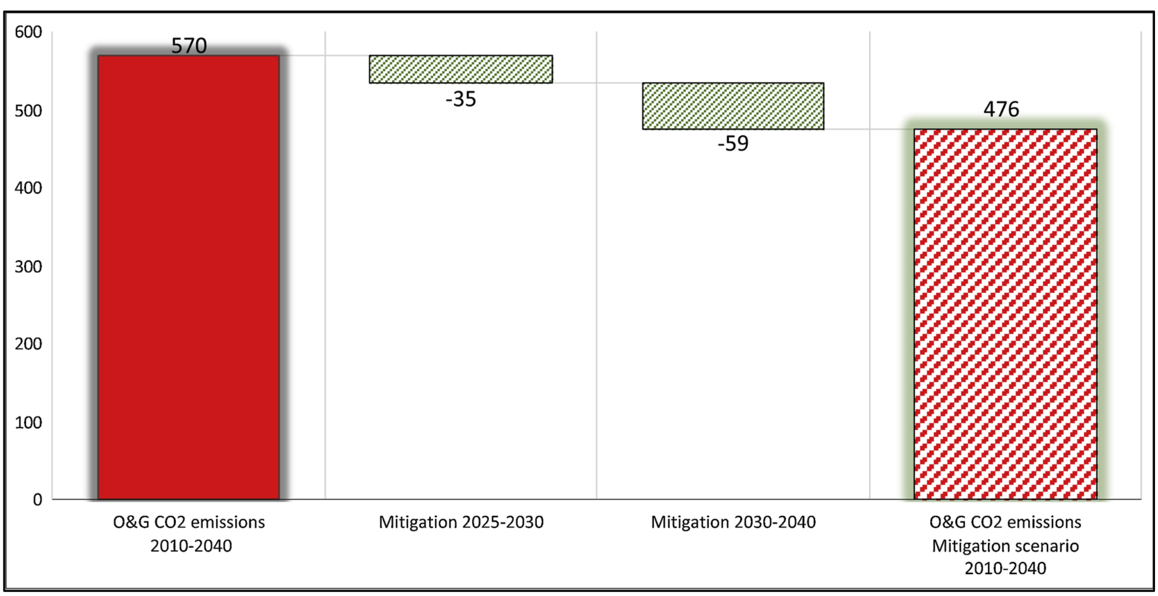


Fig. 14. CO_2 mitigation potential of the CCS-EOR technology in the Oil industry in Colombia.

production wells showed the lowest cost (57 €/tCO_2) for CCS-EOR. The highest capture cost (209 €/tCO_2) were estimated for Cluster 3, which obtains CO_2 from low-volume sources at refinery R2. However, none of these clusters offers the largest CO_2 capture and storage potential (103 $MtCO_2$) as found in Cluster 1, with values between 171 €/tCO_2 and 193 €/tCO_2 for its business cases.

The CO_2 transport cost varied between 1 €/tCO_2 for Cluster 1 with the highest volume to transport (2.7 $MtCO_2$/year) and the shortest distance (9 km), up to 23 €/tCO_2 for Cluster 4, which showed the longest network pipelines (500 km) and a relatively high CO_2 volume (0.9 $MtCO_2$/year). The CO_2 cost in EOR operations includes the injection, production, and recycling stages, and varied between 24 €/tCO_2 and 59 €/tCO_2 (both in Cluster 1) for the two business cases considered.

The CCS-EOR projects identified in this study could mitigate 24 % of the peak-year CO_2 emissions from the oil sector in 2010–2040, as expected for 2030 according to (Uniandes et al., 2014). By the same study, the accumulative CO_2 mitigations through this technology in 2025–2040 period would account for 25 % of the forecasted oil industry emissions in Colombia.

CRediT authorship contribution statement

Edgar Yáñez: Conceptualization, Data curation, Methodology, Writing - original draft, Visualization, Investigation, Formal analysis, Project administration, Resources, Writing - review & editing. **Andrea Ramírez:** Methodology, Validation, Writing - review & editing.

Vanessa Núñez-López: Validation, Writing - review & editing. **Edgar Castillo:** Writing - review & editing, Funding acquisition. **André Faaij:** Supervision, Writing - review & editing.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A

A.1 CO_2 emissions in Colombia

Figs. A1 and A2

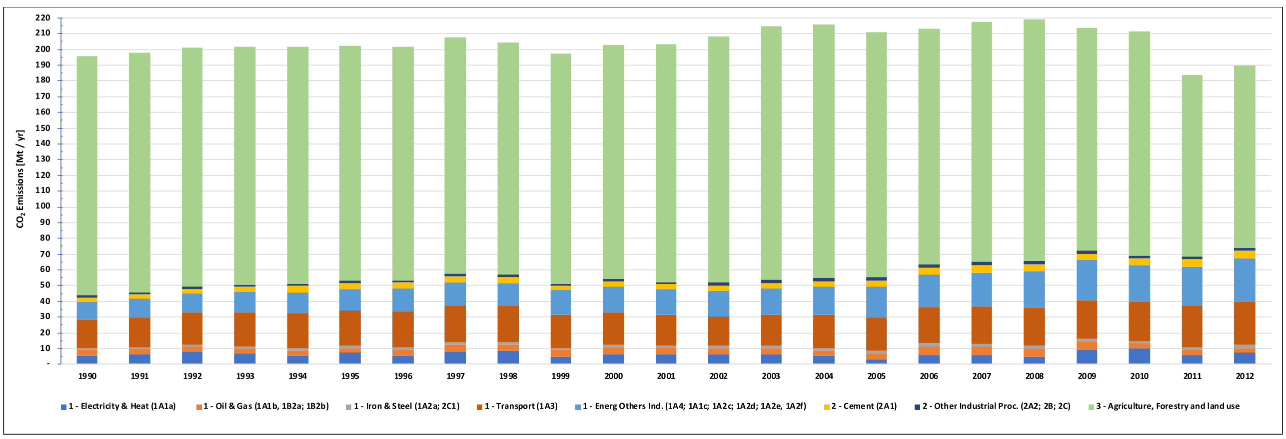


Fig. A1. Total CO_2 emissions in Colombia (IDEAM et al., 2016).

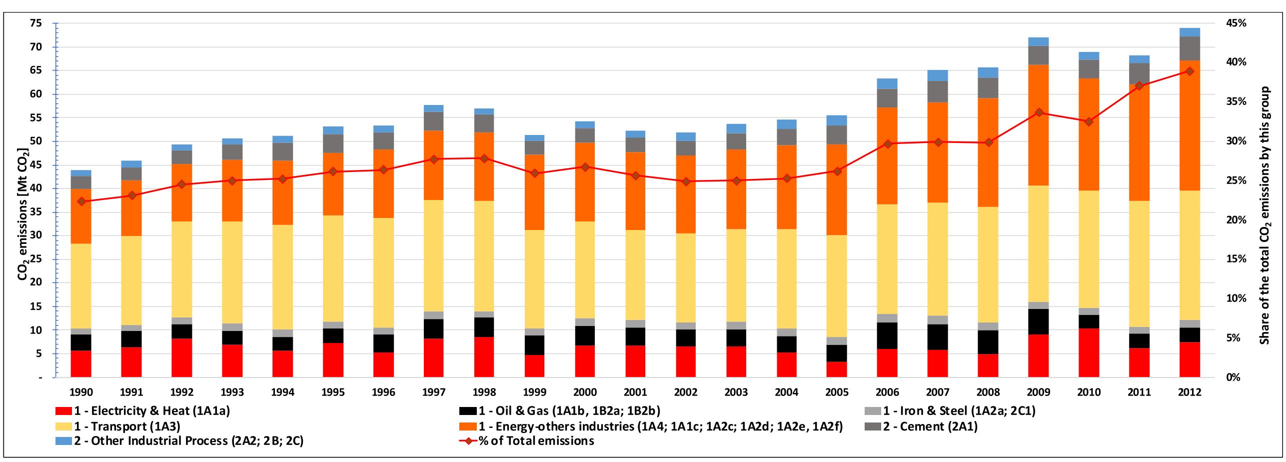


Fig. A2. CO_2 emissions from the industrial, energy and transport sector. (IDEAM et al., 2016).

A.2 CO_2 emissions factors

A.2.1 Cement industry

The utilisation factor was calculated as of 65 % using data from the national cement production and installed capacity in 2016 (DANE, 2018). (IPCC, 2000) suggest an emission factor of 0.507 t CO_2 per t Clinker. The clinker to cement ratio was calculated as of 0.79 using production data from (Ministerio de Minas y Energía, 2017). The average ratio for Latin America is 0.73; (WBCSD and IEA, 2010). Emissions from the cement industry was calculated as follow:

$$CO_2 emission\left[{}^{t}/_{yr}\right] = I_c * \left({}^{Ck}/_{Cm}\right)_r * U_f * E_f \quad (13)$$

Where:

I_c: *Installed capacity* $\left[{}^{t\ cement}/_{yr}\right]$;

$\left({}^{Ck}/_{Cm}\right)_r$: *Clinker to Cement ratio* $\left[{}^{t\ clinker}/_{t\ cement}\right]$

U_f: *Utilization factor*, [%]

E_f: *Emissions factor* $\left[{}^{t\ CO_2}/_{t\ clinker}\right]$

A.2.2 Power generation

The CO_2 emissions for each thermoelectric plant were calculated based on an average operating factor of 75 % according to (XM, 2017) and emission factors estimated by (UPME et al., 2016). The electricity produced by each plant was calculated from its installed capacity and the utilisation factor. The CO_2 emissions were calculated using Eq. 14.

$$CO_2 emission\left[{}^{t}/_{yr}\right] = I_{Pw} * R_t * U_f * E_f * cf \tag{14}$$

Where:

I_{Pw}: *Power Installedcapacity*, $[MW]$

R_t: *Running time*, $[hours]$

U_f: *Utilization factor*, [%];

E_f: *Emissions factor* $[{}^{MgCO_2}/_{TJ}]$

cf: *conversion factor* $= 0.0036\ TJ/MWh$

A.2.3 Bio-Ethanol

CO_2 emissions were estimated based on a emission factor of 0.968 tCO_2 per ton of anhydrous ethanol produced (Ecopetrol S.A., 2012b). CO_2 emissions per factory were estimated using the emission factor, the annual ethanol production (Fedebiocombustibles, 2018) and a capacity factor of 56 %[6] using Eq. 15.

$$CO_2 emission\left[{}^{t}/_{yr}\right] = I_{alc} * 365 * U_f * \rho_{alc} * E_f * {}^{1}/_{1000} \tag{15}$$

Where:

I_{alc}: *Alcohol installed capacity*, $\left[{}^{liters}/_{day}\right]$

U_f: *Utilizationfactor*, [%];

ρ_{alc}:*density of anhydrous alcohol, [kg/l];*

E_f: *Emission factor*, $[{}^{t\ CO_2}/_{t\ ethanol}]$

Density of anhydrous ethanol is assumed as of 0.79 as determined by (Torres et al., 2002).

A.2.4 Oil industry

CO_2 emission by process facility at yearly basis was collected from the Atmospheric Emission Management System (SIGEA in Spanish) from Ecopetrol (Ecopetrol S.A., 2012a). CO_2 emissions index per process used in this study are provided in (Yáñez et al., 2018)

A.3 CO_2 emissions sources inventory

Table A1

A.4 Calculation steps of the CO_2-EOR potential. Taken from (Yáñez et al., 2019)

The oil recovery potential was calculated using a Recovery factor (R_f) and the OOIP for each basin. There are three main approaches for estimating the R_f, namely: through reservoir simulations, through the use of the empirical decline curve analysis (DCA), and from literature (Verma, 2017). The storage potential is estimated using the effective volume of CO_2 used per barrel of oil recovered (U_f), which depends both on the amount of CO_2 recycled and the total injection volume of CO_2 into the reservoir. The two parameters (R_f and U_f) are a function of geological factors such as lithology, permeability, heterogeneity, and oil properties (e.g., viscosity, gravity, chemical composition), as well as of operational factors such as injection patterns, well spacing, and the volume of CO_2 injected, which are related to the design and operation of a CO_2 flood (Peck et al., 2017). The parameters Rf and Uf were calculated in this study by using

[6] Calculated as real production divided by the net capacity according to report from (Fedebiocombustibles, 2018)

[7] National CO_2 emissions by sector as indicated by IPCC guidelines (IPCC, 2006): Refinery: 1A1b; Oil and Gas Extraction: 1B2; Cement: 2A1; Power generation: 1A1a.

Table A1
Inventory of potential CO_2 sources in the Colombian industry.

Industrial sector			Process Unit [2]	t CO_2 / year	MMscfd [1] CO_2
Petroleum	**Refinery**	**R1**	R1-H2-1	43,201	2
			R1-HDT-1	91,429	5
			R1-H2-2	19,760	1
			R1-FCC-1	296,139	16
			R1-FCC-2	352,515	19
			R1-FCC-3	187,344	10
			R1-FCC-4	75,008	4
			R1-CHP-1	730,988	39
			R1-CHP-2	131,556	7
			R1-HDT[3]-2	1,017,134	55
			R1-HCK[3]-1	194,159	10
			R1-DCK[3]	200,726	11
			Sub-Total - Refinery 1	***3,339,961***	***180***
		R2	R2-HDT-1	48,664	3
			R2-FCC-1	232,135	12
			R2-H2-1	36,233	2
			R2-CHP-1	49,464	3
			R2-CHP-2	52,300	3
			R2-CHP-3	86,536	5
			R2-CHP-4	71,639	4
			R2-CHP-6	212,430	11
			R2-HCK-1	37,953	2
			Sub-Total - Refinery 2	***827,354***	***45***
		Sub-Total - Refinery		**4,167,315**	**224**
	Upstream		F-1-TC-1	654,284	35
			F-1-TG-1	161,659	9
			F-2-FH	45,251	2
			F-2-ICE	267,159	14
			F-3-Bo	27,951	2
			F-3-ICE	78,056	4
			F-3-TG-1	290,000	16
			F-3-TG-2	79,091	4
			F-4-NatCO_2	222,926	12
			Sub-Total-Upstream	**1,826,377**	**98**
			Sub-TOTAL - Petroleum	**5,993,692**	**322**
Bio-Ethanol			Et-1	75,056	4
			Et-2	62,546	3
			Et-3	54,728	3
			Et-4	46,910	3
			Et-5	15,637	1
			Et-6	39,092	2
			Et-7	39,092	2
			Sub-TOTAL - BioEthanol	**333,060**	**18**
Cement			Cem-1	248,882	13
			Cem-2	76,575	4
			Cem-3	406,896	22
			Cem-4	278,455	15
			Cem-5	2,105,086	113
			Cem-6	517,130	28
			Cem-7	723,068	39
			Cem-8	324,277	17
			Sub-TOTAL - Cement	**4,680,369**	**252**
Power Generation			PG-G-1	463,704	25
			PG-C-1	64,622	3
			PG-C-2	150,091	8
			PG-C-3	145,921	8
			PG-C-4	321,027	17
			PG-C-5	339,789	18
			PG-C-6	343,958	19
			PG-C-7	70,876	4
			PG-C-8	131,329	7
			PG-C-9	133,414	7
			PG-C-10	131,329	7
			PG-G-2	1,039,064	56
			PG-G-3	84,071	5
			PG-G-4	82,757	4
			PG-G-5	210,177	11

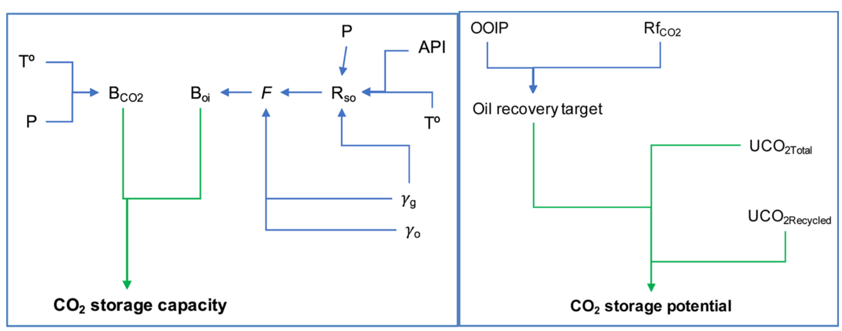
(*continued on next page*)

Table A1 (*continued*)

Industrial sector	Process Unit [2]	t CO_2 / year	MMscfd [1] CO_2
	PG-G-6	591,124	32
	PG-G-7	346,793	19
	PG-G-8	219,373	12
	PG-G-9	206,237	11
	PG-G-10	206,237	11
	PG-O-1	107,101	6
	PG-O-2	105,346	6
	PG-O-3	115,880	6
	PG-G-11	65,680	4
	PG-G-12	65,680	4
	PG-O-3	373,977	20
	PG-O-4	345,885	19
	PG-C-11	341,873	18
	Sub-TOTAL - Power Generation	**6,803,315**	**366**
GRAN TOTAL		**17,810,435**	**959**

[1] MMscfd = 50.9 t CO_2.
[2] Process unit code: R: Refinery; H2: Hydrogen production; HDT: Hydrotreatment plant; FCC: Fluid Catalytic Cracking; CHP: Cogeneration; HCK: Hydrocracking; DCK: Delayed coker; F: Upstream Facility; TC: Turbo-compressors; TG: Turbo-powers; FH: furnace/Heater; ICE: internal combustion engine; Bo: Boiler; $NatCO_2$: Natural CO_2 source; Et: Ethanol; Cem: Cement; PG: Power generation; G: gas-fired; C: Coal-fired; O: Oil-fired.
[3] Projects on development.

both a deterministic and a stochastic approach applied to the same set of candidate oilfields.



A B

Variables involved in the calculation of the CO_2 storage capacity (A) and CO_2 storage and oil recovery potentials (B).

The deterministic method, currently used in several studies in the literature, is based on the use of a fixed value (average or estimated) which generally results from expert insight, similar oil fields, or a general average derived from previous studies. This value is used to estimate the potential for oil recovery and CO_2 storage at a regional or country level once the screening of oil fields has been developed. The stochastic method, on the other hand, is based on the availability of statistical parameters (mean, median, standard deviation) for variables such as the recovery factor and the net use of CO_2 in a group of fields, region, or country. These parameters are used to estimate the potential for oil recovery and CO_2 storage through random simulation (Monte Carlo). Two databases were used for statistical variations; which included commercial projects with the results provided in Azzolina et al. (2015) and a comprehensive simulation of oil fields that was carried out in the United States as reported by Attanasi and Freeman (2016).

A.4.1 Deterministic approach

This method is based on three main steps as follows:

1 *Selecting the oil field and read the OOIP*,
2 *Calculating the Incremental oil recovery* = $N_{CO_2-Det} = OOIP \times R_{f-Det}$; *with* R_{f-Det}:*Recovery factor for use with the deterministic approach [%].*
3 *Calculating the* CO_2 *storage potential* = $CO_2EOR_{-Det} = K \times OOIP \times R_{f-Det} \times U_{f-Det}$; with U_{f-Det}: Net CO_2 utilisation factor for a deterministic approach, and K: constant value for unit conversion.

CO_2 storage capacity. The CO_2 storage capacity was estimated using a production-based CO_2 storage approach, which focuses on the cumulative production of oil fields.

$$CO_2\ Storage\ cap. = 0.05259 \times N_p \times {B_{oi}}/{B_{CO_2}}$$

(Núñez-López et al., 2008)Where:

CO_2 Storage cap: CO_2 Storage capacity, [t]
N_p: cumulative oil production [STB];

B_{oi}: oil formation volume factor, [rbbl/STB]; from Eq. (6).
B_{CO_2}: CO_2 formation volume factor (rcf/ scf; from Eq. (8).
rbbl: barrels of oil at reservoirs conditions;
STB: Stock Tank Barrel of oil (at surface P and T conditions);
rcf: volume of CO_2 in cubic feet at reservoir conditions;
scf*: Standard cubic feet;*

$$B_{oi} = 0.972 + 0.000147F^{1.175}\ with\ F = R_{so}\left(\frac{\gamma_g}{\gamma_o}\right) + 1.25T$$

(Standing, 1947)Where
R_{so}: solution oil-gas ratio; from Eq. (7)**.**
γ_g: gas specific gravity;
γ_o: oil specific gravity;
T: Temperature, [°F];

$$R_{so} = \gamma_g\left(\frac{P}{18(10)^{Y_g}}\right)^{1.204}\ with...Y_g = 0.00091T - 0.0125API$$

(Standing, 1947)Where:
R_{so}: solution oil-gas ratio;
γ_g: gas specific gravity;
P: Pressure, [psi]
API: API oil gravity;

$$B_{CO_2} = f(T,\ P)\ empirical\ 2^{nd} and\ 3^{rd} order\ polynomial.$$

(Núñez-López et al., 2008; Jarrell et al., 2002)Where:
B_{CO_2}: CO_2 formation volume factor (rcf/ scf)

CO_2 storage potential. In the deterministic approach, the net utilisation factor (U_f), as per R_f, is selected either from simulation results, analogue CO_2-EOR projects, or literature review. When the mass flows of the CO_2

$$CO_2EOR_{-Det} = 0.0283 \times OOIP \times R_{f-Det} \times U_{f-Det} \times \rho_{CO_2}$$

Where:
CO_2EOR_{-Det}: CO_2 storage potential, [t CO_2]
0.0283 is a conversion factor for units [t x m^3 / kg x mscf]
OOIP: Original Oil In Place, [STB]
R_{f-Det}: Deterministic R_f [%]
U_{f-Det}: Deterministic U_f, [mscf CO_2 /STB];
ρ_{CO_2} = 1.842 [kg/m^3], is the density of CO_2 at normal conditions (T = 20 °C, P = 1 atm)

A.4.2 Stochastic approach

The probabilistic method uses the same equations as the deterministic method, but runs a Monte Carlo simulation to randomize the main parameters such as $R_{f\text{-}St}$ and $U_{f\text{-}St}$. The main steps are as follows:

1 *Select the oil field and read the OOIP; (constant)*
2 *Run a Monte Carlo simulation for N_{CO_2-St}*
   a *Incremental oil recovery = N_{CO_2-St} = OOIP × R_{f-St}; R_{f-St} :Recovery factor for the stochastic approach [%].*
   b $R_{f-St} \sim$ lognormal $(\mu_{R_{f-St}}, \sigma_{R_{f-st}})$
3 *Run Monte Carlo simulation for CO_2EOR_{-St}*
   a *CO_2 storage potential = $CO_2EOR_{-St} = K \times OOIP \times R_{f-St} \times U_{f-St}$; U_{f-St}: Net CO_2utilisation factor for a stochastic approach, and K: constant value for unit conversion.*
   b $U_{f-St} \sim$ lognormal $(\mu_{U_{f-St}}, \sigma_{U_{f-st}})$

Statistical parameters from (Azzolina et al., 2015) used to randomise input variables. (Database B)

	Recovery Factor (R_{f-St} [%])		CO_2 Net Utilization (U_{f-St} [mscf/bbl])	
%HCPV	*Median*	*SD* [1]	*Median*	*SD* [1]
50 %	2.7	2.0	13.8	10.0
100 %	9.9	7.3	10.6	3.5
200%	11.7	4.6	9.4	2.4
300%	12.2	5.1	8.7	2.2

[1]SD: Standard deviation
Statistical parameters from Attanasi and Freeman (2016) used to randomise input variables. (Database A)

	Recovery Factor (R_{f-St} [%])		CO_2 Net Utilization (U_{f-St} [mscf/bbl])	
	Median	*SD* [1]	*Median*	*SD* [1]
Carbonate	13.74	2.27	5.25	0.60
Clastic	9.86	1.56	5.93	0.64
Total	11.35	2.65	5.67	0.71

[1] *SD: Standard deviation*

A.5 CO_2 capture in the industry

A.5.1 Cement

Cement production emissions are mainly produced during calcination (60 %), and the remaining are attributable to the heat generation for the kiln, both amenable to CO_2 capture. The cement industry, however, has been cautious about incorporating new technologies that might affect the chemical nature of clinker (Leeson et al., 2017).

A detailed study of the CO_2 capture in the cement industry found post-combustion as the only option with low risk and retrofitting potential in the short term (Kuramochi et al., 2012). However, solvent regeneration (MEA) uses a significant amount of heat (4 MJ/tCO_2). New technologies such as the calcium-looping capture technology appear to have as twice as energy efficient as using the solvent MEA with an energy penalty of 2.8 MJ/tCO_2 (Vatopoulos and Tzimas, 2012). Nevertheless, post-combustion with the use of modern solvents such as piperazine or proprietary BASF/Linde solvents achieve similar duties of $2.5-3$ MJ/tCO_2 (Boot-Handford et al., 2014).

Oxy-combustion is also a promising technology for CO_2 capture in the cement industry (IEAGHG, 2013). It can be implemented using a partial or full integrated concept into the clinker production depending on where oxygen is used (only in the pre-calciner or also in the kiln). Although thermal energy demand is slightly affected, the electrical demand can increase as twice per ton of cement (IEAGHG, 2013). Even though oxyfuel technology shows the lower cost of CO_2 avoided and around half the increase in cement production cost compare to post-combustion (IEAGHG), there is still a discussion about the adverse effects of high oxygen concentrations on the kiln damage and formation of NO_x compounds at high temperatures (Leeson et al., 2017).

A.5.2 Oil refinery

CO_2 emissions in the refinery are mainly produced during heat and power generation which account for around 64 %, FCC process with 31 % and the remaining from hydrogen production (Yáñez et al., 2018).

As presented by (Kuramochi et al., 2012), post-combustion using solvents is the feasible option in the short term considering the CO_2 is at low partial pressure in the refinery. Results from (Kuramochi et al., 2012), show that Oxyfuel technology promise to reduce by half the CO_2 avoidance cost compare to the post-combustion cost which is around 100 €/tCO_2, and additionally lower the SO_2 and NO_x emissions. However, the avoidance cost in post-combustion can be reduced and competitive when using low-value steam. Pre-combustion was also identified in his study as a promising technology (e.g. Sorption Enhanced Water-Gas Shift -SEWGS process), but unlike the oxyfuel process, boilers and furnaces can burn hydrogen with no modification. Their final assessment present post-combustion technology as the most attractive option in the short term by cost, maturity and retrofitting feasibility.

In a site-specific CO_2 capture technology assessment the refineries, (Berghout et al., 2013) report that oxyfuel technology shows the lowest CO_2 avoidance costs (24-57€/tCO_2) compare to post-combustion (69-80€/tCO_2). Heat requirement in post-combustion increased as much as 60 % in comparison with the base case. Oxyfuel, however, maintained a similar heat production as the reference case but electricity consumption went up to 80 % more than post-combustion technology due to oxygen production. This study also estimated that oxyfuel technology could reduce around 64 %CO_2 emissions in the refinery (including CO_2 capture of additional heat) meanwhile post-combustion achieve up to 81–87 % reductions. Additionally, (Berghout et al., 2013) calculates CO_2 avoidance cost for the hydrogen production varying between 67 to 126€/tCO_2, showing the lowest cost if captured from the high-pressure process such as the WGS-PSA. According to this author, post-combustion technology seems to improve competitiveness for smaller emitter sizes and besides its long experience in the natural gas sector promote this technology as the most feasible process to be implemented in the refinery.

In a recent study by (Berghout et al., 2019), the cost of CO_2 avoided calculated for oxyfuel and post-combustion technologies are much closer than in previous studies with 76 and 71€/tCO_2 respectively, when credits from the sale of surplus electricity are included. These lower costs are also due to a combined capture of all suitable sources rather than individual capture process. Post-combustion continues to show the highest emission reduction capacity (approximately 90 %) compared to the other capture technologies.

Considering the lifetime of a refinery, it is very likely that the implementation of capture processes will occur within a retrofit plan. In this regard, (IEAGHG, 2017) developed a study to estimate the cost of retrofitting in a refinery that uses post-combustion technology as a CO2 capture method. The estimated costs are much higher than those reported in the literature, with a range of 160 to 210$/tCO2. The higher costs are due to this study included the costs of capture, but also industrial services (utilities), interconnection (piping, ducting, etc.) and the non-synergy with other processes within the refinery. Finally, the IEAGHG report used investment costs commissioned to *Amec Foster Wheeler*, which is a well-known global engineering company with considerable experience on refineries, which provide essential insights about cost involved in retrofitting.

A.5.3 Power generation

A recent study from (IEAGHG, 2018a) argues that post-combustion using solvent scrubbing is currently the leading option for CO_2 capture at both pulverised coal and natural gas-fired power plants. A well-known setback of carbon capture in power generation plants is the energy efficiency penalty. According to (IEAGHG, 2018a), the net efficiency loss was around 9 and 7 percentage points for coal and gas-fired plants respectively compared to the cases without capture. The plant cost is strongly affected by an increase of 90–110 % by the introduction of post-combustion. Regarding electricity costs, there is a sharp difference between a plant with and without capture. The levelised cost of electricity (LCOE) increase from a range of 35-58€/MWh in a base case to 67-106€/MWh for a coal-fired plant with CO_2 capture and similarly for a gas-fired plant from 28 to 66 €/MWh to 48-93€/MWh.

A.5.4 Ethanol

The sugarcane based-ethanol production is based on a fermentation process that emits high-purity CO_2 (> 95 %) which is considered pure for storage as summarised by (Rochedo et al., 2016). Thus, CO_2 capture in ethanol plants is composed of a CO_2 dehydration process to avoid the carbonic acid formation and then compression to inject it into the transportation network. In this study, CO_2 capture cost (dehydration and compression of CO_2) in ethanol plants is calculated using the improved cost model for CO_2 transport by pipeline developed by (Knoope et al., 2014).

A.6 CO_2-EOR costs model

A.6.1 Injection

This module estimates the associated cost to injection and injection wells. As summarize by (Tayari et al., 2018), lease equipment cost is usually calculated as a function of depth per well. The injection equipment and injection well costs are estimated using a linear regression model proposed by (Tayari et al., 2018) which used secondary oil recovery operations data from West Texas published by the United States Energy Information Administration (EIA). (Eq. (16))

$$Ci_{LEq} = (200{,}32 \times D) - 97{,}718 \tag{16}$$

Where:

Ci_{LEq}:Lease equipment cost (equipment + well) during injection, [€$_{2017}$]

D:Dept; [ft]

The annual operation and maintenance (O&M) cost refer to the workover of wells including tubing replacement due to corrosion caused by CO_2 (see Eq. (17)). This cost also uses a linear regression model including three elements as follows:

$$\begin{aligned} Ci_{O\&M} &= Ci_d^{O\&M} + Ci_S^{O\&M} + Ci_{Sbs}^{O\&M} \\ Ci_d^{O\&M} &= (3.3514 \times D) + 18{,}717 \\ Ci_S^{O\&M} &= (0.844 \times D) + 6{,}098 \\ Ci_{Sbs}^{O\&M} &= (2.9019 \times D) + 5{,}785 \end{aligned} \tag{17}$$

Where:

$Ci_{O\&M}$: Total annual O&M cost, [\$,$_{2017}$]

$Ci_d^{O\&M}$: Normal daily O&M cost[\$,$_{2017}$]

$Ci_S^{O\&M}$: Surface repair cost, [\$,$_{2017}$]

$Ci_{Sbs}^{O\&M}$: Subsurface repair cost, [\$,$_{2017}$]

CO_2 Distribution cost is estimated as a fixed cost associated with all manifolds and distribution lines on the site between the production wells and the recycle plant as suggested by (Tayari et al., 2018). The fixed CO_2 distribution cost is assumed as of \$$_{2014}$200,000 per injection well. Even though a variable component can also be included, it depends on distance and flow rate which are out of the scope of this study.

Surfactants and polymers are used to improve the efficiency of oil recovery. (Tayari et al., 2018) discusses the costs and doses of surfactants and polymers used during EOR operations which should be customized to the reservoir and oil properties. It finally assumes a foaming anionic surfactant without sacrificial surfactant with a cost of (\$$_{2014}$ 7.72/kg), delivered at a concentration of 25 % by weight which cost \$$_{2014}$ 1.93/kg and injected with a concentration of 0.05 wt%. The surfactant cost is calculated following Eq. (18).

$$Ci_{Sft} = \left(\frac{(100 \times Ic)}{Sc}\right) \times C_{As} \times W_p \times 10^6 \times 42 \times 3.785/100 \tag{18}$$

Where:

Ci_{Sft}:Total surfactant cost, [€$_{2017}$]

Ic:Solution concentration at injection, [wt%]; assuming a solution density of 1 kg/L.

Sc:Active surfactant concentration, [wt%]

C_{As}: Active surfactant cost, [€/kg]

W_p: Volume of water injected, [million bbl];

Water cost has two components: supply cost (or purchasing cost) and water/surfactant pumping and injection cost. For the water supply is assumed there is access to subsurface water with a cost of \$0.14/bbl (Advanced Resources International and ARI, 2014), which represent only the energy cost for lifting from a well depth of 7500 ft. The water/surfactant (brine) injection cost is calculated as the energy cost required to boost the injection pressure up to reach the bottom hole pressure plus the hydrostatic pressure. (Eq. (19) to Eq. (21))

$$Ci_{ws_i} = C_{elect} \times Pw_c \tag{19}$$

$$Pw_c = BHP \times R_t \tag{20}$$

$$BHP = \frac{Q \times (P_d - P_s)}{1714 \times ME} \tag{21}$$

Where:

Ci_{ws_i}:Water/surfactant injection cost, [€$_{2017}$]

C_{elect}:Electricity cost, [€/kWh]

Pw_c:Power consumption, [kWh/year]

BHP:Horsepower of the pump, [hp]

R_t:Running time, [hours]

Q:Fluid flow rate, [gallons/minute]

P_d:Discharge pressure, [psi]

P_s:Initial pressure, [psi]

ME:Mechanical efficiency of the pump

A.6.2 Production

Production cost comprises the additional equipment costs of producing wells, the fluid lifting cost and the water/oil separation cost. Production equipment costs are calculated as a function of well depth. A fit linear regression model to data reported by EIA and proposed by (Tayari et al., 2018) was used in this study (Eq. (22)).

$$C_{op_e} = (17.151 \times D) - 11{,}156 \tag{22}$$

Where

C_{op_e}:Production equipment cost, [€$_{2017}$]

D:Dept; [ft]

Fluid lifting is necessary when the reservoir pressure is not higher than the hydrostatic pressure of a column of produced fluids in the well. (Tayari et al., 2018) describes a range of lifting cost between 0.14–3.8$\$_{2014}$/bbl but assumed a charge of 0.25$\$_{2014}$/bbl as reported by (Advanced Resources International and ARI, 2014).

Water/oil separation cost include separation, de-oiling and filtering process. Base on a report from Schlumberger described by (Tayari et al., 2018), previous costs were assumed as 0.12$\$_{2014}$/bbl, 0.17$\$_{2014}$/bbl and 1.16$\$_{2014}$/bbl respectively.

A.6.3 Recycling

A share of CO_2 injected is produced along with oil. CO_2 breakthrough occurs at a production well in a mixture gas phase with natural gas which is separated from the liquid phase at the surface. CO_2 is then compressed and re-injected into the reservoir (IEA, 2015a). Typically, 15–50% of CO_2 injected is recycled into the reservoir through this process (Holtz et al., 1999) with the CO_2 compression cost as high as 60–80% of the total electricity cost of a CO_2-EOR project (Van Leeuwen et al., 2009). As summarised by (Tayari et al., 2018), there are two methods to calculate recycling costs as follow: the straight refrigeration method based on peak utilisation (Advanced Resources International and ARI, 2014) and the independent cost model for separation and compression. This study use the first method as follow.

Capital cost of recycling plant is calculated based on a peak rate lower or higher than 30MMscf/day (Eqs. (23) and (24)). This total cost includes separation processes for gas/liquid, water/oil, and CO_2/hydrocarbon gas and dehydration and compression of CO_2.

$$R_{C<30} = 1{,}200{,}000 \times P_r \tag{23}$$

$$R_{C>30} = 36{,}000{,}000 + (P_r - 30) \times 750{,}000 \tag{24}$$

Where

$R_{C<30}$: Capital cost, [$,$_{2008}$]; when peak rate is < 30 MMscf/day

$R_{C<30}$: Capital cost, [$,$_{2008}$]; when peak rate is > 30 MMscf/day

P_r: Peak rate, [MMscf/day]]

Similarly, the Natural Gas Liquid recovery (NGL) plant, additional cost are estimated as follow by Eqs. (25) and (26).

$$NGL_{C<20=350{,}000\times P_r} \tag{25}$$

$$NGL_{C>20} = 7{,}000{,}000 + (P_r - 20) \times 25{,}000 \tag{26}$$

Where

$R_{C<30}$: Capital cost, [$,$_{2008}$]; when peak rate is < 20MMscf/day

$R_{C<30}$: Capital cost, [$,$_{2008}$]; when peak rate is > 20MMscf/day

P_r: Peak rate, [MMscf/day]

A.7 CO_2 transport cost model

A.7.1 Pipeline

The Investment costs of a pipeline are estimated from material cost, labour cost, right-of-way and miscellaneous costs (Knoope et al., 2014) (See Eq. (27)). From a comprehensive study by (Knoope et al., 2013), is suggested that material cost on pipeline infrastructure should be estimated from the weight of the pipeline, which is related to the steel grade (Eq. (28)).

$$I_{pipe} = I_{pipe_M} + I_{pipe_L} + I_{pipe_{ROW}} \tag{27}$$

$$I_{pipe_M} = t\pi \times (OD_{NPS} - t) \times L \times \rho_{steel} \times C_{steel} \tag{28}$$

Where:

I_{pipe_M}:Material cost for the pipeline, [€]

t:Thickness, [m]

OD_{NPS}:Outer diameter of the nominal pipe size, [m]

L:Length of the pipeline, [m]

ρ_{steel}:Density of steel, 7900 [kg/m^3]

C_{steel}:Steel cost, [€/kg]

Labour cost is estimated using an average cost for developed countries from (Knoope et al., 2014) and then adjusted by a location factor reported by (IEAGHG, 2002). The average cost as of 825€/m^2 (21€/inch/m) is based on the FERC cost database for pipelines constructed in the period 2008-2012. The right-of-way (ROW) cost is calculated as a fixed amount per meter length of 83€/m for the onshore pipelines reported in the FERC database and described by (Knoope et al., 2014).

A.7.2 Compression

The specific investment cost of compression proved to vary significantly between different estimates due mainly to the installation factors assumed (Knoope et al., 2014). Eq. (29) depicts a standard scaling formula based on the approach used by (Kreutz et al., 2005) as summarized by

(Knoope et al., 2014), which better reflect the valuation of material costs provided by vendors.

$$I_{comp} = I_o \times \left(\frac{W_{comp}}{W_{comp,o}}\right)^{SF} \times n^{me} \tag{29}$$

Where

I_{comp}:Investment cost of the compressor, [M€]
I_o:Base cost, [= 21.1M€]
W_{comp}:Capacity of the compressor, [MWe]
$W_{comp,o}$:Base scale of the compressor, [= 13MWe]
SF:Scaling factor, [= 0.67]
n:number of units in parallel, [1,2]
me:multiplication exponent, [= 0.9]

A.7.3 Energy consumption in compressors

The capacity and energy consumption of compressors is calculated following Eqs. (30) and (31) as summarized by (Knoope et al., 2014). Assuming a CO_2 inlet pressure of 0.11 MPa (temperature of 30 °C) and a maximum compressor ratio of 2.04, six compression stages are needed to reach the outlet pressure of 8 MPa. Since the CO_2 is liquid at the sixth stage, pumping is required to increase its pressure up to the required pressure.

$$E_{comp} = \sum_{x=1}^{X} \frac{Z_x \times R \times T \times k_x}{M \times \eta_{iso} \times \eta_{mech} \times (k_x - 1)} \times \left[\frac{p_{2,x}}{p_{1,x}}^{\left((k_x-1)/k_x\right)} - 1\right] + \frac{P_2 - P_1}{\eta_{pump} \times \rho} \tag{30}$$

$$W_{comp} = E_{comp} \times m \tag{31}$$

Where:

E_{comp}:Energy consumption of compression, [kJ/kg]
x:Compression stage number for total X stages.
Z_x:Compressibility factor of CO_2 in stage x.
R:Universal gas constant, [= 8.3145 J/mol/K]
T:Inlet temperature compressor stage, [= 303.15 K]
k_x:Specific heat ratio of the CO_2 in stage x
M:Molecular mass of CO_2, [= 44.01 g/mol]
η_{iso}:Isentropic efficiency of the compressor, [80 %]
η_{mech}:Mechanical efficiency of the compressor, [99 %]
$p_{2,x}$:Outlet pressure of compression stage x, [MPa]
$p_{1,x}$:Inlet pressure of compression stage x, [MPa]
P_2:Outlet pressure of the pump, [MPa]
P_1:Inlet pressure of the pump, [= 7.7 MPa]
η_{pump}:Efficiency of the pumping equipment, [= 75 %]
W_{comp}:Capacity of the compressor, [kWe]
m:Mass flow, [kg/s]

A.7.4 Pumping stations

Investment costs of pumps are estimated using Eq. (32) which are based on water pump design as there are not significantly difference with CO_2 pumps.

$$I_{pump} = 74.3 \times W_{pump}^{0.58} \times n^{0.9} \tag{32}$$

Where:

I_{pump}:Investment costs of pumping stations, [k€]
W_{pump}:Capacity of pumping stations per unit, [kW_e]
n:number of units in parallel

A.7.5 Energy consumption in pumping stations

The capacity and energy consumption by the pumping stations is calculates as shown by Eqs. (33) and (34) (IEAGHG, 2002).

$$E_{pump} = \frac{P_2 - P_1}{\eta_{pump} \times \rho} \tag{33}$$

$$W_{pump} = E_{pump} \times m \tag{34}$$

E_{pump}:Energy consumption of pumping, [MJ/kg]
P_2:Outlet pressure, [MPa]
P_1:Inlet pressure, [MPa]
η_{pump}:Efficiency of the pumping station, [= 75 %]
ρ:Density, [kg/m^3]
W_{pump}:Capacity of pumping station, [MWe]
m:Mass flow, [kg/s]

A.8 Ranking of potential regions to deploy CO_2 –EOR

Table A2

Table A2
Ranking of potential regions to deploy CO_2-EOR projects.

Criteria	Range	Value	Weighted factor	Region 1	Region 2	Region 3	Region 4	Region 5
Distance	Low	1	0.2	1	1			
	Media	0.3				1	1	
	High	0.1						1
Origin of CO_2 captured	Oil sector	1	0.15	1	1	1		1
	Another sector	0.5					1	
Capture feasibility	High	1	0.1	1	1		1	
	Medium	0.7				1		
	Low	0.1						1
Volume of CO_2	High	1	0.25	1		1		
	Medium	0.7					1	
	Low	0.1			1			1
Infrastructure	High	1	0.1	1				
	Medium	0.6			1	1	1	
	Low	0.1						1
Number of sinks available	Med-high	1	0.1	1	1		1	
	Low	0.5				1		1
CO_2 sources location	Concentrated	1	0.1	1	1			
	Scattered	0.3				1	1	1
Total				**1**	**0.74**	**0.67**	**0.6**	**0.3**

Potential CO_2 sources and oil fields by clusters.

A.9 Potential CO_2 sources and oil fields by clusters

Table A3

Table A3
Potential CO_2 sources and oil fields for CO_2 -EOR projects in Colombia.

SOURCES		CLUSTER	CANDIDATE OIL FIELDS	
Code of industrial CO_2 source	CO_2 emission [Mt/yr]		Oil field name code	CO_2 Storage capacity [Mt]
R1-H2-1	0.04	**1**	A	43
R1-H2-2	0.02		E	9
R1-HDT-1	0.08		G	41
R1-FCC-1	0.27		H	64
R1-FCC-2	0.32		I	3
R1-CHP-1	0.65		J	41
R1-CHP-2	0.12			
R1-HDT-2	0.92			
R1-HCK-1	0.18			
R1-DCK	0.18			
Cem-1	0.21			
Cem-2	0.07			
Cem-3	0.35			
PG-G-1	0.42			
PG-G-7	0.31			
PG-G-8	0.20			
F-4-NatCO2	0.15	**2**	M	5
F-5-NatCO2	0.07		O	4
			Q	5
R2-HDT-1	0.04	**3**	B	12
R2-H2-1	0.03			
R2-HCK-1	0.03			
R2-FCC-1	0.21			
R2-CHP-6	0.19			
Cem-7	0.61	**4**	K	14
Et-2	0.06		N	4
Et-3	0.05		P	3
Et-4	0.05		Q	
Et-5	0.02			
Et-6	0.04			
Et-7	0.04			
5.9		**TOTAL**	**248**	

Ranking of CO_2 sources and oil field by clusters.

A.10 Ranking of CO_2 sources and oil field by clusters

Table A4
Ranking of oil fields for Cluster 1.

Oil Field -Code name	Distance to CO_2 Source [km]	CO_2 Storage Capacity [$MtCO_2$]	Oil recovery Potential [MMbbl]	Distance to source [km]			Storage Capacity [$MtCO_2$]			Oil recovery Potential [MMbbl]			Total Score
Range (threshold)				< 15	> 15 < 30	> 30	> 10	> 1 < 10	< 1	> 50	> 10 < 50	< 10	
Value				1	0.9	0.7	1	0.7	0.4	1	0.8	0.5	
Weighted factor (W_z)				0.4	0.4	0.4	0.3	0.3	0.3	0.2	0.2	0.2	
H	5	64	219	1			1			1			**0.90**
A	12	43	145	1			1			1			**0.90**
J	34	41	139			1	1			1			**0.78**
G	55	41	140			1	1			1			**0.78**
E	29	9	19		1			1			1		**0.73**
I	11	3	7	1				1				1	**0.71**
Total		**201**	**668**										

Table A5
Ranking of CO_2 sources for Cluster 1.

CO_2 source- code name	Sector		Operational status		CO_2 concentration			Distance to oil fields [km]			Total Score	CO_2 capture Potential [Mt/yr]
Range	Oil sector	Other	Running	On Project	High > 75 %	Medium > 45 %	Low < 45 %	Low < 50	Medium 50-100	High > 100		
Value	0.8	0.2	1.0	0.5	1.0	0.7	0.5	1	0.7	0.5		
Weighted factor (W_x)	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1		
R1-H2-1	1		1		1			1			0.92	0.04
R1-H2-2	1		1		1			1			0.92	0.02
R1-HDT-1	1		1			1		1			0.86	0.08
R1-FCC-2	1		1				1	1			0.82	0.32
R1-CHP-1	1		1				1	1			0.82	0.65
R1-FCC-1	1		1				1	1			0.82	0.27
R1-CHP-2	1		1				1	1			0.82	0.12
R1-HDT-2	1			1		1		1			0.71	0.92
R1-HCK-1	1			1			1	1			0.67	0.18
R1-DCK	1			1			1	1			0.67	0.18
PG-G-8		1	1				1	1			0.58	0.20
PG-G-7		1	1				1		1		0.55	0.31
Cem-2		1	1				1		1		0.55	0.07
Cem-3		1	1				1			1	0.53	0.35
PG-G-1		1	1				1			1	0.53	0.42
Cem-1		1		1			1			1	0.38	0.21
Total												**4.33**

Table A6
Ranking of CO_2 sources for Cluster 2.

CO_2 source- code name	Sector		Operational status		CO_2 concentration			Distance to oil fields [km]			Total Score	CO_2 capture Potential [Mt/yr]
Range	Oil sector	Other	Running	On Project	High > 75 %	Medium > 45 %	Low < 45 %	Low < 50	Medium 50-100	High > 100		
Value	0.8	0.2	1.0	0.5	1.0	0.7	0.5	1	0.7	0.5		
Weighted factor	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1		
F-4-NatCO2	1		1		1			1			0.92	0.15
F-5-NatCO2	1		1		1			1			0.92	0.07
Total												**0.22**

Table A7
Ranking of oil fields for Cluster 2.

Oil Field - Code name	Distance to Source [km]	CO_2 Storage Capacity [$MtCO_2$]	Oil recovery Potential [MMbbl]	Distance to CO_2 source [km]			Storage Capacity [$MtCO_2$]			Oil recovery Potential [MMbbl]			Total Score
Range				< 15	> 15 < 30	> 30	> 10	> 1 < 10	< 1	> 50	> 10 < 50	< 10	
Value				1	0.9	0.7	1	0.7	0.4	1	0.8	0.5	
Weighted factor				0.4	0.4	0.4	0.3	0.3	0.3	0.2	0.2	0.2	
M	43	5	11			1		1			1		**0.65**
O	33	4	9			1		1				1	**0.59**
Q	40	5	16			1		1			1		**0.65**
Total		**9**	**20**										

Table A8
Ranking of CO_2 sources for Cluster 3.

CO_2 source- code name	Sector		Operational status		CO_2 concentration			Distance to oil fields [km]			Total	CO_2 capture Potential [Mt/yr]
Range	Oil sector	Other	Running	On Project	High > 75 %	Medium > 45 %	Low < 45 %	Low < 50	Medium 50-100	High > 100		
Value	0.8	0.2	1.0	0.5	1.0	0.7	0.5	1	0.7	0.5		
Weighted factor	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1		
R2-HDT-1	1		1			1				1	0.81	0.04
R2-H2-1	1		1		1					1	0.87	0.03
R2-HCK-1	1		1				1			1	0.77	0.03
R2-FCC-1	1		1				1			1	0.77	0.21
R2-CHP-6	1		1				1			1	0.77	0.19
Total												**0.51**

Table A9
Ranking of oil fields for Cluster 3.

Oil Field - Code name	Distance to Source [km]	CO_2 Storage Capacity [$MtCO_2$]	Oil recovery Potential [MMbbl]	Distance to CO_2 source [km]			Storage Capacity [$MtCO_2$]			Oil recovery Potential [MMbbl]			Total Score
Range				< 15	> 15 < 30	> 30	> 10	> 1 < 10	< 1	> 50	> 10 < 50	< 10	
Value				1	0.9	0.7	1	0.7	0.4	1	0.8	0.5	
Weighted factor				0.4	0.4	0.4	0.3	0.3	0.3	0.2	0.2	0.2	
B	200	12	41				1				1		**0.46**
Total		**12**	**41**										

Table A10
Ranking of CO_2 sources for Cluster 4.

CO_2 source- code name	Sector		Operational status		CO_2 concentration			Distance to oil fields [km]			Total Score	CO_2 capture Potential [Mt/yr]
Range	Oil sector	Other	Running	On Project	High > 75 %	Medium > 45 %	Low < 45 %	Low < 50	Medium 50-100	High > 100		
Value	0.8	0.2	1.0	0.5	1.0	0.7	0.5	1	0.7	0.5		
Weighted factor	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1		
Cem-7		1	1				1	1			0.58	0.61
Et-2		1	1		1					1	0.63	0.06
Et-3		1	1		1					1	0.63	0.05
Et-4		1	1		1					1	0.63	0.05
Et-5		1	1		1					1	0.63	0.02
Et-6		1	1		1					1	0.63	0.04
Et-7		1	1		1					1	0.63	0.04
Total												**0.87**

Table A11
Ranking of oil fields for Cluster 4.

Oil Field - Code name	Distance to Source [km]	CO_2 Storage Capacity [$MtCO_2$]	Oil recovery Potential [MMbbl]	Distance to CO_2 source (Cem-7) [km]			Storage Capacity [$MtCO_2$]			Oil recovery Potential [MMbbl]			Total Score
Range				< 15	> 15 < 60	> 60	> 10	> 1 < 10	< 1	> 50	> 10 < 50	< 10	
Value				1	0.9	0.7	1	0.7	0.4	1	0.8	0.5	
Weighted factor				0.4	0.4	0.4	0.3	0.3	0.3	0.2	0.2	0.2	
K	150	14	47			1	1			1			**0.78**
N	40	4	9		1			1				1	**0.67**
P	56	3	5		1			1				1	**0.67**
Total		**21**	**62**										

CO_2 storage and incremental oil recovery potential by clusters and sector in Colombia.

A.11 CO_2 storage and incremental oil recovery potential by clusters and sector in Colombia

Table A12
CO_2 storage potential [Mt CO_2].

	Cluster 1	Cluster 2	Cluster 3	Cluster 4	TOTAL
Oil	2.77	0.22	0.51	–	3.50
Cement	0.62	–	–	0.61	1.24
Power	0.93	–	–	–	0.93
Ethanol	–	–	–	0.26	0.26
TOTAL	4.33	0.22	0.51	0.87	5.93

Table A13
Incremental oil recovery potential [MMbbl].

	Cluster 1	Cluster 2	Cluster 3	Cluster 4	TOTAL
Oil	219	36	41	–	296
Cement	58	–	–	43	101
Power	87	–	–	–	87
Ethanol	–	–	–	18	18
TOTAL	364	36	41	62	503

A.12 Calculation of royalty percentage according to oil production volumes (Congreso de la República de Colombia, 2002)

Oil production volume [bbl/day]	Royalty [%]
< = 5000	8 %
5,000–125,000	8 % + (Vo - 5)*0.1 %
125,000–400,000	20 %
400,000–600,000	20 % + (Vo -400)*0.025 %
> 600,000	25 %

Where
Vo = volume of oil production [kbpd]]

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